

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08
HBC, PA
RJS

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

DIRECT TESTIMONY OF
LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

OCTOBER 8, 2008

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EXETER

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

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Introduction and Summary

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. I am a Senior Regulatory Analyst with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Business Administration degree from The George Washington University. The major area of concentration for this degree was Finance. I received a Bachelor of Business Administration degree with concentration in Accounting from North Carolina Central University. I am also a Certified Public Accountant licensed in the State of North Carolina.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From May 1984 until June 1990, I was employed by the North Carolina Utilities Commission - Public Staff in Raleigh, North Carolina. I was responsible for analyzing testimony, exhibits, and other data presented by parties before the North Carolina Utilities Commission. I had the additional responsibility of performing the examinations of books and records of utilities involved in rate proceedings and summarizing the results into testimony and exhibits for presentation before that Commission. I was also involved in numerous special projects, including participating in compliance and prudence audits of a major utility and conducting research on several issues affecting natural gas and electric utilities.

1 From June 1990 until July 1993, I was employed by Potomac Electric Power
2 Company (Pepco) in Washington, D.C. At Pepco, I was involved in the preparation of
3 the cost of service, rate base and ratemaking adjustments supporting the company's
4 requests for revenue increases in the State of Maryland and the District of Columbia.
5 I also conducted research on several issues affecting the electric utility industry for
6 presentation to management.

7 In July 1993, I accepted my current position with Exeter Associates, Inc. Since
8 then, I have been involved in the analysis of the operations of public utilities, with
9 particular emphasis on utility rate regulation. I have also been involved in the review and
10 analysis of utility rate filings, focusing primarily on revenue requirements determination.
11 This work has involved natural gas, water, electric and telephone companies.

12 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY**
13 **PROCEEDINGS ON UTILITY RATES?**

14 A. Yes. I have previously presented testimony and affidavits on numerous occasions before
15 the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission,
16 the Virginia Corporation Commission, the Louisiana Public Service Commission, the
17 Georgia Public Service Commission, the Maine Public Utilities Commission, the
18 Kentucky Public Service Commission, the Public Utilities Commission of Rhode Island,
19 the Vermont Public Service Board, the Illinois Commerce Commission and the Federal
20 Energy Regulatory Commission (FERC).

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

23 A. Exeter Associates has been retained by the Office of Consumer Advocate (OCA) to
24 review the reasonableness of the level of revenues which Equitable Gas Company
25 (Equitable or the Company) is proposing to charge its customers. In this testimony,

1 I present my findings on behalf of the OCA regarding certain adjustments to Equitable's
2 future test year rate base and net operating income at present rates. In addition, I also
3 present a summary of the OCA's findings regarding the current levels of Equitable's
4 earnings and determine the necessary change in its revenues that is required to produce an
5 overall rate of return on rate base of 7.46 percent. This return is based on the
6 recommendation of OCA witness David Parcell.

7 **Q. IN CONNECTION WITH THIS CASE, HAVE YOU PERFORMED AN**
8 **EXAMINATION AND REVIEW OF THE COMPANY'S TESTIMONY**
9 **AND EXHIBITS?**

10 A. Yes. I have reviewed Equitable's testimony and exhibits, its rate filing, as well as its
11 responses to the OCA's and other parties' data requests.

12 **Q. WOULD YOU PLEASE SUMMARIZE WHAT IS PRESENTED ON THE**
13 **ATTACHED SCHEDULES?**

14 A. Yes. I have prepared a set of schedules that present my findings and recommendations
15 regarding the Company's rate base and net operating income. Schedule LKM-1
16 summarizes my overall findings regarding net operating income. Schedule LKM-2
17 presents a summary of rate base and my adjustments thereto. Schedule LKM-3
18 summarizes each of my adjustments to Equitable's net income. Schedule LKM-4
19 presents a reconciliation of current income taxes. The remaining schedules show the
20 derivation of each of my adjustments to rate base and net operating income.

21 **Q. PLEASE SUMMARIZE YOUR FINDINGS.**

22 A. I have determined the appropriate change in Equitable's distribution revenues to be a
23 \$29.4 million increase as compared to the Company's request of \$51.9 million. This
24 revenue change is based on the level of rate base and cost of service that I am
25 recommending and Mr. Parcell's rate of return recommendation. When the cost of

1 service is adjusted to correct for the overstatement of the universal service costs as
2 recommended by OCA witness Roger Colton, the revenue requirement increase is \$21.8
3 million. When the disallowance of the negotiated rate discounts as recommended by
4 OCA witness Glenn Watkins is reflected, the OCA's recommended change in revenues
5 would be a decrease of \$1.5 million. This represents a reduction of \$53.4 million in the
6 Company's requested distribution revenue increase.

7 The OCA recommended distribution revenue change would result in a 0.28
8 percent decrease in distribution revenue instead of 10.0 percent proposed by the
9 Company. The chart below summarizes the adjustments I am recommending:

10

Description	Rate Base	Revenues	O&M Expenses
Post Test Year Plant in Service	\$(1,761,629)	\$	\$
Cash Working Capital	(5,707,957)		
Operating Revenues		22,790,905	
Lobbying Expenses			(123,593)
Regulatory Commission Expense			(298,781)
Collection Costs			(612,202)
Anode Expenses			(269,658)
Customer Experience Expenses			(636,686)
PA One Call Expenses			(83,197)
Fuel Expenses			(69,623)
Injuries & Damages Expense			(2,755,953)
Right-of-Way Mowing Expense			(384,431)
Cathodic Protection			(133,524)
Postretirement and Pension Expense			(463,473)
Payroll Expense			(342,428)
Universal Service			(7,339,228)

11
12 **Q. WHAT TIME PERIOD DID YOU USE IN YOUR ANALYSIS OF THE**
13 **COMPANY'S OPERATING RESULTS?**

14 A. The Company's filing includes revenue requirement analyses based upon both a
15 historical test year ended December 31, 2007 and a future test year ending December 31,
16 2008. I have based my analysis of the Company's operating results on the future test year

1 ending December 31, 2008. This is the same period used by the Company to determine
2 its requested rate increase in its rate filing, direct testimony and exhibits.

3 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

4 A. The remainder of this testimony addresses each of the adjustments that I am
5 recommending and is presented in the order identified in the table of contents to this
6 testimony. For each issue, I will document and explain why it was necessary to make the
7 adjustment.

8
9 **Rate Base Adjustments**

10 **Plant in Service**

11 **Q. WHAT ADJUSTMENTS ARE YOU RECOMMENDING BE MADE TO**
12 **PLANT IN SERVICE?**

13 A. Equitable has made a claim in the future test year to include Construction Work In
14 Progress (CWIP) that it claims will be completed and placed in service within six months
15 after the end of the future test year. Some of the projects that Equitable has included as
16 CWIP are actually stand alone assets that will be acquired within six months after the end
17 of the future test year. Unlike CWIP, stand alone assets are not projects that require
18 construction to develop the final asset that is placed in service. For the most part, stand
19 alone assets can be placed in service almost immediately after acquisition. As a result,
20 they are not projects that existed at the end of the future test year. Instead, they are
21 expenditures that are projected to be made after the end of the test year. As a result, the
22 inclusion of these costs in plant in service is not consistent with the Commission's
23 practice of recognizing non-revenue producing CWIP that existed as of the end of the
24 future test year as being eligible for rate base inclusion.

1 Since the stand alone assets are not in accordance with Commission practice, I am
2 recommending an adjustment that removes the cost of these assets of \$1,761,627 from
3 the future test year plant in service on Schedule LKM-5. This adjustment brings the
4 Company's plant in service into compliance with Commission practice.

5 **Q. DOES YOUR ADJUSTMENT TO RECOGNIZE NON-REVENUE**
6 **PRODUCING CWIP INDICATE YOU BELIEVE RECOGNIZING CWIP**
7 **IS APPROPRIATE?**

8 A. No. CWIP does not represent plant that is used and useful as of the end of the test year.

9 In addition, including CWIP results in a mismatch among the elements of rate base
10 because it fails to recognize that depreciation and deferred taxes will continue to accrue
11 during the time period that the CWIP is being completed and placed in service. Finally,
12 including CWIP in rate base results in a mismatch between revenues, expenses and rate
13 base. However, I recognize that the Commission has traditionally allowed the inclusion
14 of non-revenue producing and non-expense reducing CWIP, which will be placed in
15 service within six months of the end of the test year, to be included in rate base.
16 Accordingly, I have made this adjustment to be consistent with Commission practice.

17
18 **Allowance for Cash Working Capital**

19 **Q. HOW DO YOU DEFINE CASH WORKING CAPITAL?**

20 A. For ratemaking purposes, cash working capital is the investment that a utility needs to
21 have on hand to fund its day-to-day operations. Positive cash working capital represents
22 funds provided by investors that should be included in rate base so that the Company
23 earns a return on it. Negative cash working capital represents funds supplied by
24 ratepayers that should be recognized as a rate base offset.

1 **Q. HOW DID THE COMPANY REFLECT CASH WORKING CAPITAL IN**
2 **ITS FILING?**

3 A. The Company's cash working capital allowance is calculated based upon the results of a
4 lead-lag study. A lead-lag study is an in-depth analysis that measures the difference
5 between the lapse of time when the Company receives revenue for the provision of
6 service and the lapse of time when the Company pays for the costs of providing service.
7 This difference, expressed as a number of days, is used to calculate the level of investor-
8 supplied funds advanced for operations if the difference is positive. If the difference is
9 negative, it is used to calculate the funds advanced by customers.

10 The revenue lag represents the average number of days from the date on which
11 service is provided to the customers until the date on which payment is received from the
12 customers. It is measured from the midpoint of the service period covered by the bill to
13 the date payment for that service is received by the Company. The Company's expense
14 lag, or payment lag, represents the average number of days from the date the expense is
15 incurred in rendering service until the date the expense is paid. It is also measured from
16 the midpoint of the service period to the date the expense is paid.

17 After both the Company's revenue lag and expense payment lag have been
18 determined, one can make a reasonable approximation of the Company's cash working
19 capital requirement. This calculation is made by dividing the expenses by 365 days to
20 determine the average daily amount. The average daily amount is multiplied by the net
21 lead-lag days (the difference from subtracting the expense lag from the revenue lag) to
22 derive the Company's working capital requirements. If the total working capital
23 requirement is positive, it represents a level of funds that must be included in rate base so
24 that the Company is provided a return on the funds supplied by investors. Conversely, if

1 the amount is negative, then the amount reduces rate base to recognize funds that
2 customers have advanced.

3 **Q. PLEASE DEFINE THE TERMS "LEAD" AND "LAG" AS YOU USE**
4 **THEM IN YOUR TESTIMONY.**

5 A. The term "lead" is used to indicate either the receipt of revenue prior to the date that
6 service is provided or the payment of an expense prior to the date that the expense is
7 incurred. The term "lag" is used to indicate either the receipt of revenue after the date
8 that service is provided or the payment of an expense after the date that the expense is
9 incurred.

10 **Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE ALLOWANCE**
11 **FOR CASH WORKING CAPITAL?**

12 A. I have reviewed the supporting documentation for the lead-lag study and disagree with
13 the determination of the lead-lag days attributed to certain components of the lead-lag
14 study. I have made corrections to the components as necessary, and will discuss each of
15 these corrections.

16 **Q. WHAT IS THE FIRST CORRECTION THAT YOU MADE TO THE**
17 **LEAD-LAG STUDY?**

18 A. The first correction I have made to the lead-lag study involves the lag days assigned to
19 the short-term incentive compensation paid to both union and non-union employees. The
20 short-term incentive compensation is paid based upon achieving certain corporate and
21 individual goals annually. If the goals have been achieved by the end of the current year,
22 the incentive compensation is paid to eligible employees in the following year. The fact
23 that the incentive compensation is paid in the year following the current year is not
24 reflected in the company's lag day calculation. This is wrong because the payment lag
25 days should reflect the actual period over which the service was performed. This error

1 causes an increase in the cash working capital. Specifically, the short-term incentive
2 compensation earned during 2006 was paid on February 6, 2007. The Company
3 calculated the service period as if it were earned during the period January 14, 2007
4 through January 23, 2007 instead of the period over which it was earned (January 1, 2006
5 through December 31, 2006). The service period used by the Company grossly distorts
6 the short-term incentive plan payment lag because it treats the incentive compensation as
7 if it was earned in the previous two weeks rather than the previous year. Therefore, I
8 have corrected the payment lag days to reflect the actual period over which the short-term
9 incentive compensation was earned. On Schedule LKM-6, pages 2 and 3, I present the
10 recalculation of the payroll lag for union and non-union employees. In addition to
11 correcting the service period to reflect the actual service period for the short-term
12 incentive compensation, I have also corrected the non-union short-term incentive
13 compensation amount to remove an error made by the Company. In the response to
14 OTS-RE-18-D, Equitable indicated that the correct short-term incentive compensation
15 amount paid was \$3,650,116 instead of the \$3,557,439 that was used in cash working
16 capital supporting documentation.

17 **Q. ARE THERE ANY OTHER COSTS IN THE LEAD-LAG STUDY THAT**
18 **ARE AFFECTED BY THE SHORT-TERM INCENTIVE**
19 **COMPENSATION SERVICE PERIOD?**

20 A. Yes. The short-term incentive compensation service period affects the lag on the 401(k)
21 matching costs and the payroll tax lag. The Company's 401(k) matching contribution is
22 based upon a percentage of the payroll. Whenever there is a payroll payment, there is a
23 corresponding 401(k) matching contribution. Hence, just as there is an additional pay
24 period for the short-term incentive compensation, there is a corresponding 401(k)
25 matching contribution. Equitable calculated the 401(k) matching as if it was earned in

1 the previous two weeks. As I explain in my discussion of the short-term incentive
2 compensation lag, this is wrong. Therefore, on Schedule LKM-6, page 3 I have shown
3 the correction of the 401(k) matching lag days to reflect the actual service period (the
4 previous year) over which the 401(k) related to the incentive compensation was earned.
5 This service period is the same as the service period I used to calculate the short-term
6 incentive compensation payment lag.

7 The other costs that are affected by the short-term incentive plan service period
8 are payroll taxes. Equitable explains in its filing that payroll taxes are paid at the same
9 time the payroll is paid. Accordingly, Equitable's payroll taxes lag is the same as its
10 payroll lag. As a result of the correction in the payroll lag that I have made, there is a
11 corresponding change in the payroll taxes lag. I have presented this change on Schedule
12 LKM-6, page 10.

13 **Q. PLEASE EXPLAIN THE NEXT CORRECTION THAT YOU HAVE**
14 **MADE TO THE COMPANY'S LEAD LAG STUDY.**

15 A. The next correction I have made to Equitable's lead-lag study involves the Corporate
16 Services lag. Corporate Services expenses are Equitable's share of costs that it receives
17 through charges from its parent company and affiliates. In the lead-lag workpapers, the
18 Company calculates the lag days on Corporate Services as if it is paid on the last day of
19 each month. In 8 of the 12 months presented, the costs are exactly the same. Therefore,
20 it appears that the bills could not have been the actual costs incurred during the month,
21 and that it is not likely to have been paid on the last day of the month since the company
22 has to go through the month-end closing to formally determine the costs. Month-end
23 closing usually takes a few days to complete, so the amount the Company claims to have
24 paid on the last day could not be the actual closed costs. Moreover, the use of the same
25 amount in those eight months indicates that the amount is an estimate, not the actual

1 amount, because the Company should be charged based upon actual activity during the
2 month. The monthly activity generally varies from month to month.

3 In the response to OCA I-45, Equitable stated that it does not, in fact, receive a
4 bill from corporate services and that no cash payments are actually made. This means
5 that the costs recorded on Equitable's books are essentially settled through accounting
6 entries. However, the calculation presented by the Company presents the costs as if there
7 is a cash payment on average approximately 15 days from the mid-point of the service
8 period. This time period is not an accurate portrayal of settlement of the costs.
9 Therefore, I have corrected the lag on corporate services by using the revenue lag days
10 instead of the Company's assumption. The use of revenue lag days is appropriate
11 because it reflects how the account actually is settled. By using the revenue lag, the costs
12 are treated as being paid as collected and results in having no net effect on working
13 capital. This treatment is consistent with the fact that no cash is exchanged in payment of
14 these costs and with the Company's treatment of uncollectibles, which is also a non-cash
15 expense. I have shown this calculation on Schedule LKM-6, page 4.

16 **Q. WHAT IS THE NEXT CORRECTION YOU HAVE MADE?**

17 A. The next correction I made is to the Other Expense lag. In the response to OTS-RE-23-
18 D, the Company indicated that there was an error in one of the payment dates given for
19 one of its vendors, C. Leon Sherman & Associates PC. I have corrected the lag days to
20 reflect the correct payment date for that vendor as provided by Equitable. The corrected
21 lag day calculation is presented on Schedule LKM-6, pages 5 and 6.

22 **Q. WOULD YOU EXPLAIN YOUR NEXT CORRECTION TO THE CASH**
23 **WORKING CAPITAL?**

24 A. Yes. The next correction I made is to the pension and benefits lag days. The change in
25 the lag days is the result of corrections to two components of costs in that category. The

1 first component is the lag days for the 401(k) matching contribution that I have explained
2 was caused by the correction of the short-term incentive compensation service period
3 from the previous two weeks to the previous year.

4 The second component is the service period used for executive health exams.
5 In the Company's workpapers, Equitable incorrectly calculates the lag days based upon a
6 service that begins on January 1, 2007, and extends through December 31, 2007.
7 According to the response to OTS-RE-30-D, each of the qualified individuals is offered
8 one health exam annually at Company expense. Each of the health exams occurred on
9 specific dates for each of the individuals. The health exam is the service that was
10 received and for which the payment was made.

11 The Company made an error in the service period it used to measure the payment
12 lag. As I indicate at the outset of the cash working capital section of this testimony, the
13 payment lag is supposed to measure from the mid-point of the period in which the service
14 was performed to the payment date for that service. The Company's calculation treats
15 the service lag as if the executive health exams were performed every day during 2007.
16 Clearly, this was not what happened because Equitable provided specific dates on which
17 the exams were done. As a result of this error, I have corrected the lag days for executive
18 health exams using the date on which the exam occurred as the service period. The
19 resulting amounts and dollar days have been reflected in the overall lag days for pension
20 and benefits presented on Schedule LKM-6, page 7.

21 **Q. WHAT IS THE NEXT CORRECTION YOU MADE TO THE LEAD-LAG**
22 **STUDY?**

23 A. The next correction I made to the Company's lead-lag study involves the payroll taxes
24 lag days. In the lead-lag study, Equitable explains that payroll taxes are paid on the same
25 date as the payroll. Accordingly, the Company indicates that the payroll taxes lag is the

1 same as the payroll lag. I do not disagree with the notion that the payroll taxes lag is the
2 same as the payroll lag. However, the calculation of the lag days applied to the Taxes
3 Other Than Income Expense category in the lead-lag study did not include the payroll
4 taxes even though the Taxes Other Than Income expenses, to which those lag days were
5 applied, includes the payroll taxes.

6 When the OCA sought an explanation of this discrepancy, the Company
7 responded that payroll taxes are included with payroll expenses since they are paid at the
8 same time. That response implies that, in the lead-lag study, the payroll expense amount
9 includes the payroll taxes, and that payroll taxes have been removed from Taxes Other
10 Than Income. However, the Company's statement is not accurate. When the O&M
11 Expense and Taxes Other Than Income amounts presented in the lead-lag study
12 (Company Exhibit VI, Item 18, Page 2) are compared with similar amounts presented in
13 the cost of service (Company Future Test Year Exhibit III-A-17, Sheets 4 and 6), it is
14 clear that payroll taxes are, in fact, included in Taxes Other Than Income and not Payroll
15 Expense in the lead-lag study. Therefore, I have corrected this error by recalculating the
16 Taxes Other than Income lag by including payroll taxes at a payment lag equal to the
17 payroll lag days. This calculation is presented on Schedule LKM-6, page 10.

18 **Q. ARE THERE ANY OTHER CORRECTIONS OR CHANGES THAT YOU**
19 **HAVE MADE TO THE LEAD-LAG STUDY?**

20 A. Yes. As I discuss later in this testimony, I have made several adjustments to O&M
21 expenses and taxes in the cost of service, which are additional components used by the
22 Company in the lead-lag study. Since I have concluded that the adjustments I have made
23 are necessary to establish reasonable rates, those adjustments must also be incorporated
24 into the lead-lag study. On Schedule LKM-6, page 1, I have incorporated those
25 adjustments into the lead-lag study.

1 Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO CASH WORKING
2 CAPITAL.

3 A. As a result of the corrections that I have discussed above , I am recommending an
4 adjustment to reduce cash working capital by \$5,707,957. This adjustment is presented
5 on Schedule LKM-6, page 1.
6

7 **Operating Revenues**

8 **Sales Revenues**

9 Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO SALES REVENUES.

10 A. I have made an adjustment to increase sales revenues by \$22,790,905. This adjustment is
11 the recommendation of OCA witness Glenn Watkins, and is supported in his direct
12 testimony.
13

14 **Expense Adjustments**

15 **Collection Costs**

16 Q. WHY HAVE YOU REVERSED THE COMPANY'S CLAIM THAT
17 INCLUDES COLLECTION COSTS IN O&M EXPENSES?

18 A. Equitable has made a pro forma adjustment to increase O&M expenses by \$612,202 to
19 reclassify collection costs that were recorded in accounts receivable to operating
20 expenses. Although the Company has proposed this adjustment, it admits that its normal
21 accounting practice is to include collection costs in accounts receivable and that the
22 adjustment it is proposing is not an adjustment to correct an error. Moreover, Equitable
23 states that an adjustment to reclassify collection costs has not actually been made on its
24 books.

1 Upon further inquiry, the Company indicated in response to OCA VIII-12 that
2 these were third party collection costs that had increased since the last rate case.
3 According to Equitable, these costs are not included in current base rates, so it recorded
4 them against the accounts receivable reserve, and is now including them in O&M
5 expenses in an attempt to begin recovering these costs. Equitable states that the actual
6 entry has not been made but that such an entry will be made pending the outcome of this
7 proceeding.

8 **Q. DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT?**

9 A. No. The Company's adjustment is inappropriate for three reasons. First, the Company
10 adjustment constitutes retroactive ratemaking. The Company's own words describe the
11 costs as costs incurred since the last rate case that were not included in current base rates.
12 By including those collection costs in this proceeding, the Company is attempting to
13 recover costs which were accumulated before the test year when the rates established
14 were deemed reasonable. Retroactive ratemaking is not allowed by this Commission.

15 Second, the Company's accounting for these collection costs is essentially an
16 unauthorized deferred accounting for these costs. In accounting for these costs, the
17 Company has accumulated costs in the accounts receivable reserve, which were not
18 included in the cost of service when current rates were established, and is now seeking to
19 pass through to customers in rates to be established from this proceeding. The deferral of
20 costs in a prior period and recovery in a subsequent period must be authorized by the
21 Commission. The Company has not received such authorization.

22 Finally, even though these costs were accumulated over time, Equitable is seeking
23 to recover the entire \$612,202 as if they are annually recurring collection costs, when it
24 does not incur such annually recurring costs. If these costs are included at this level,
25 O&M expenses will be overstated by \$612,202.

1 Based on the foregoing discussion, I am recommending the Company's
2 adjustment of \$612,202 be disallowed. As shown on Schedule LKM-8, I have removed
3 these costs from the cost of service. There is still an outstanding data request on this
4 issue. Upon receiving this response I will update this adjustment if necessary.

5
6 **Anode Expenses**

7 **Q. WHY HAVE YOU RECOMMENDED AN ADJUSTMENT TO REDUCE**
8 **EQUITABLE'S CLAIMED O&M EXPENSES FOR COSTS RELATED TO**
9 **ANODES?**

10 A. Equitable describes an anode as an electrode through which electric current flows into a
11 polarized electronic device to distribute cathodic protection to pipes. Historically, these
12 costs were expensed during the period they were incurred. During the historic test year,
13 the Company recorded \$1,269,658 in O&M expenses as costs related to the use of anodes
14 for cathodic protection. Beginning in 2008, the Company changed its accounting policy
15 after it was confirmed that cathodic protection extends the useful life of steel pipes. As a
16 result, the costs related to cathodic protection are now being capitalized. The Company's
17 adjustment removes \$1,000,000 from the cost of service in an attempt to recognize that
18 these costs would no longer be recorded as O&M expenses on an ongoing basis.
19 However, the removal of the \$1,000,000 does not include the entire amount incurred
20 during the test year for cathodic protection (\$1,269,658).

21 The Company's reason for removing only \$1,000,000 from the cost of service is
22 that it estimates that amount to be the level of costs related to anodes that will be
23 capitalized during the future test year. However, removing \$1,000,000 leaves \$269,658
24 in operating expenses related to cathodic protection in cost of service. Equitable,
25 however, claims these costs are representative of routine inspection of anodes and

1 corrosion. Yet, the Company has also included costs for inspection activities in its
2 maintenance expense adjustment. As a result, some of these costs are duplicative. The
3 OCA has sought additional information on this matter, and will update this adjustment if
4 necessary.

5 The \$269,658 adjustment that I am recommending is necessary to remove the
6 remaining expenses that are included in O&M expenses related to cathodic protection
7 because the Company stated they will no longer be recognized as O&M expenses on an
8 ongoing basis. On Schedule LKM-9, I present this adjustment, which decreases O&M
9 expenses by \$269,658. There is an outstanding data request on this issue. Upon
10 receiving the response, I will update this adjustment if necessary.

11 **Customer Experience Study**

12 **Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE CUSTOMER**
13 **EXPERIENCE STUDY COSTS?**

14 A. During 2007, the Company conducted an in-depth customer experience study. The
15 Company expects to use the study results as the baseline from which future customer
16 experience can be evaluated. The study was conducted after a number of significant
17 changes were made to the Company's operations. Specifically, Equitable had completed
18 the installation of a new customer information system, an Automated Meter Reading
19 system, a mobile dispatching/work order management system, and it expanded call center
20 service hours.

21 In the response to OCA I-26, Equitable acknowledges that customer experience
22 surveys are not performed annually and in fact could be performed with differing scopes.
23 Hence, I am recommending an adjustment that recognizes the infrequent nature of such
24 studies. Given the significant costs of \$795,858 that the Company claims for the study, I

1 am recommending an adjustment to normalize these costs over a 5-year period. The 5-
2 year period is consistent with the period I used for the normalization of regulatory
3 commission expenses and is consistent with Commission precedent for such expenses.
4 On Schedule LKM-10, I have reduced O&M expenses by \$636,686 to normalize
5 customer experience study costs.
6

7 **PA One Call Expense**

8 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S PA**
9 **ONE CALL EXPENSE.**

10 A. Equitable has included the cost of a recent contract with an outside contractor that
11 provides line location and other services. The costs included in the cost of service were
12 based upon a billing rate of \$17.50 per unit. In addition, Equitable claimed public
13 awareness and work management support costs in deriving the total annual cost of
14 \$572,183 for this contract.

15 I have reviewed the Company's contract with the vendor of these services in
16 conjunction with my evaluation of the costs included in the cost of service. My
17 adjustment corrects the billing rate per unit to be consistent with the contract with the
18 vendor and removes the public awareness and work management support costs because
19 they are not incremental costs.

20 With regard to the billing rate per unit, I have used the rate per unit that is stated
21 in the contract. According to the contract that rate will be fixed for three years.
22 Therefore, it is appropriate to use this rate. With regard to the public awareness and work
23 management support costs, the Company indicates that these costs were previously
24 incurred. Since the Company's claim is intended to include the costs of the new contract,
25 only new costs related to the contract should be reflected. Therefore, I have removed the

1 public awareness and work management support costs from the cost of service because
2 they are not incremental costs and are already included in the cost of service. I have
3 presented my adjustment, which reduces O&M expenses by \$83,197, on Schedule LKM-
4 11.

5
6 **Lobbying Expenses**

7 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO LOBBYING EXPENSES.**

8 A. The Company's cost of service includes a total of \$123,593 in lobbying expenses. Out of
9 the total amount, \$122,009 was charged to the Company through corporate service
10 charges from its affiliates and/or its parent company. The remaining \$1,584 is calculated
11 based upon two percent of Equitable's American Gas Association (AGA) dues.
12 According to Equitable's response to Standard Data Request, Item No. 33, two percent of
13 AGA's operating budget is attributable to lobbying activities. Therefore, I have
14 attributed two percent of the Company's AGA dues as supporting lobbying activities.

15 **Q. WHY HAVE YOU REMOVED LOBBYING EXPENSES?**

16 A. For ratemaking, a utility's costs of service should include only those costs that are
17 necessary for the provision of utility service. Under traditional ratemaking principles,
18 lobbying is not considered an activity necessary for the provision of utility service.
19 Consequently, I have removed those expenses from the cost of service. This adjustment
20 is presented on Schedule LKM-12, resulting in a \$123,593 decrease in O&M expenses.

21
22 **Payroll and Benefits Expenses**

23 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PAYROLL EXPENSES.**

24 A. The Company's payroll claim is based upon adjusting the historic test year payroll
25 expense to an ongoing level based upon changes that were to occur by the end of the

1 future test year. The historical test year was first adjusted to include open positions that
2 the Company expected to be filled and to remove the costs associated with positions that
3 were transferred to other affiliates. Next, the Company included a claim for a three
4 percent merit rate increase, promotions and other allocated labor costs, and the costs of
5 newly hired employees. These series of adjustments reflected the payroll expense at the
6 ongoing level at the end of the future test year. Further, Equitable added the costs of
7 fringe benefits. The fringe benefits costs were derived by applying the fringe benefits
8 rate to the future test year payroll costs. The fringe benefits rate was calculated based
9 upon the ratio of the fringe benefits paid during the historical test year to the payroll paid
10 during the same period.

11 The adjustment I made removes the costs associated with positions that are not
12 currently filled and a position that was included twice. With regard to the positions that
13 were not filled, the Company's response to OCA I-11 identifies each of the positions that
14 were included in its adjustment to include the costs of newly hired employees. There
15 were four positions that were identified as not being filled. I have removed the costs
16 associated with those four positions in order to reflect the most recent actual number of
17 employees. The use of the actual number of employees is reasonable because these
18 positions are newly created positions based upon an anticipated expansion.
19 Consequently, there is some uncertainty regarding if, or when, these positions will be
20 filled. If these costs are included in rates, and the positions are not filled, the Company
21 will over-recover these costs. Moreover, there is always a level of unfilled positions due
22 to employee attrition. Removing these costs is necessary to eliminate payroll costs that
23 will not be incurred.

24 With regard to the position that was included twice, it appears that both the costs
25 of the former employee and the replacement employee were inadvertently included in the

1 payroll. The former employee left the Company on December 31, 2007, and was
2 replaced by an employee that was hired in January 2008. The cost of the former
3 employee remained in the Company's payroll claim, and a merit increase was even added
4 on the historical test year amount. The Company also included the annual cost of the
5 person hired to fill the former employee's position in its adjustment to reflect newly hired
6 employees. As a result, the position is included twice in the payroll claim and must be
7 removed.

8 In addition to the removal of the payroll costs, I have removed the fringe benefits
9 associated with each position. This is necessary since fringe benefits were included for
10 each position based upon a percentage of payroll costs. On Schedule LKM-13, I present
11 this adjustment resulting in a \$342,428 decrease in O&M expenses.

12
13 **Pension and Postretirement Benefits Other Than Pensions**

14 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PENSIONS AND**
15 **POSTRETIREMENT BENEFITS OTHER THAN PENSION.**

16 *The Company's future test year claims for pension and postretirement benefits other than*
17 *pensions were the historical test year amounts for these expenses. The Company has*
18 *provided the 2008 actuarial study for these costs. The adjustment I am recommending is*
19 *necessary to include the 2008 actuarial amounts rather than the historical test year*
20 *amounts. The use of the 2008 amounts is more appropriate because they reflect the most*
21 *recent costs. On Schedule LKM-14, I present this adjustment that reduces O&M*
22 *expenses by \$463,473.*

1 **Regulatory Commission Expenses**

2 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REGULATORY**
3 **COMMISSION EXPENSES.**

4 A. Equitable has increased the claimed cost of service to normalize the cost of this rate
5 proceeding over a three-year period, and to normalize the costs of the Service Life Study
6 and the upcoming management audit over a five-year period. The adjustment I am
7 recommending changes the normalization period and removes costs that have not been
8 incurred.

9 First, I have removed the upcoming management audit costs. These costs were
10 removed because the audit has not yet begun and the costs the Company is seeking to
11 recover have not been incurred. As a result these costs are not eligible for recovery in
12 current rates.

13 The second change I have made is to normalize the cost of this proceeding over a
14 five-year period. The three-year period proposed by the Company should not be used
15 because it normalizes rate case expense over a period that is much shorter than the period
16 between this case and the last rate case, which was filed on February 28, 1997. The use
17 of the five-year period is also consistent with the period the Company proposed to
18 normalize the management audit and the Service Life Study.

19 Finally, in the Company's response to OCA IV-8, Equitable identified certain
20 costs that were related to its West Virginia jurisdiction. The Company admits that these
21 costs should not be included in Pennsylvania jurisdictional rates. Therefore, I have
22 removed them from regulatory commission expenses to be recovered in this proceeding.
23 The adjustment I am recommending is summarized on Schedule LKM-15 and results in a
24 \$298,781 decrease to O&M expenses.

1 **Cost of Fuel**

2 **Q. WHAT ADJUSTMENT HAVE YOU MADE TO COST OF FUEL?**

3 A. Equitable made an adjustment to include the increased cost of gasoline and diesel fuel
4 used by its vehicles. The Company's adjustment was based upon the escalation of the
5 historical test year costs by approximately 25 percent to reflect recent spikes in gasoline
6 and diesel fuel prices. In response to an OCA interrogatory, the Company indicated that
7 it had installed GPS devices in all its vehicles, which have resulted in a 7.5 percent
8 decrease in the average miles driven. In addition, vehicles are now required to be turned
9 off at service stops. Accordingly, the Company's data for 2008 shows a decrease in the
10 number of gallons of fuel consumed by the Company. However, this reduction was not
11 reflected in Equitable's cost of service claim for fuel costs.

12 The adjustment I am recommending is necessary to reflect the net decrease in the
13 cost of fuel experienced by the Company that has resulted from its changes in policy that
14 require turning off vehicles and the use of GPS devices. Essentially, the fuel cost borne
15 by the Company has two components -- a price component and a usage component. The
16 Company's adjustment captures the price component, but not the usage component. To
17 properly reflect the fuel costs, it is necessary to also reflect the changes in the usage. The
18 adjustment I have made combines both the price and usage changes and results in a net
19 *increase in fuel costs. I derived my adjustment by annualizing the Company's actual fuel*
20 usage for the first eight months of 2008 and the Company's 2008 price per gallons rates
21 that it used in its adjustment. The result is decrease of \$69,623. This adjustment is
22 presented on Schedule LKM-16.

1 **Injuries and Damages**

2 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO INJURIES AND**
3 **DAMAGES EXPENSE.**

4 A. Under current accounting practices, a company must record, as an expense, potential
5 claims for which it may be liable during the period in which the Company determines
6 liability is likely to be incurred. Each year the Equitable accrues these costs as expenses
7 to injuries and damages expenses and records the corresponding liability amount in a
8 reserve account. Later during the year, the reserve account is analyzed to determine
9 whether the amount recorded is adequate to meet potential claims. An adjustment (the
10 adjusting entry) is made (either an increase or decrease) to bring the value of the reserve
11 more in line with the Company's actuarial expectations.

12 During the historical test year, as a result of the reserve analysis, Equitable made
13 an adjusting entry to reduce the reserve account by \$3,145,292 because it was found to be
14 too high. The adjusting entry made by the Company to reduce the reserve also reduced
15 the injuries and damages expense by \$3,145,292. In the cost of service in the rate case,
16 the Company made an adjustment to normalize the injuries and damages expense. In that
17 adjustment, Equitable essentially reverses the \$3,145,292 adjusting entry that reduced
18 injuries and damages in its historical test year operating expenses. With this adjustment
19 the Company considers the injuries and damages expense to be normalized.

20 I disagree with the Company's adjustment because Equitable treats the adjusting
21 entry as if it is an unusual or one-time occurrence. It is not. An adjusting entry is made
22 virtually every year to recognize changes in the actuarial estimates that are used to record
23 the monthly expense. Through quarterly reviews the adequacy of the reserve is assessed,
24 as explained in the Company's response to OTS-RE-87-D. Because of this process of
25 accruing the expense and later "correcting" through the adjusting entries, it is necessary

1 to combine the expense accrual and the adjusting entry to derive the annual expense. The
2 adjustment proposed by the Company results in an overstatement of the injuries and
3 damages expense because it removes the adjusting entry that is needed to properly reflect
4 the injuries and damages expense.

5 The adjustment I have made normalizes the injuries and damages expense using
6 the actual claims paid by the Company. In addition, I used a three-year average of actual
7 claims paid as the normalized expense amount. It is more appropriate to use my
8 approach because the actual claims are the actual cash payments made by the Company
9 to settle claims. It is preferable because the accrued expense, which is reflected on the
10 Company's books, is always an estimate. That is why adjusting entries are routine.

11 In addition, I have used the three-year average because claims have a tendency to
12 fluctuate from year to year. The three-year average smooths out the fluctuations and
13 normalizes the level of expenses.

14 **Q. WHAT IS THE RESULT OF YOUR ADJUSTMENT TO INJURIES AND**
15 **DAMAGES?**

16 A. The adjustment I am recommending is a reduction in O&M expense of \$2,755,953. This
17 adjustment is presented on Schedule LKM-17.

18
19 **Right-of-Way Mowing**

20 **Q. WHY DID YOU ADJUST THE LEVEL OF EXPENSE RELATED TO**
21 **RIGHT-OF-WAY MOWING?**

22 A. Equitable increased O&M expense by \$384,431 because it wanted to normalize its right-
23 of-way mowing expense. According to the Company, the basis of the adjustment was to
24 include an amount that is associated with the mowing of its gathering and transmission
25 facilities right-of-way. I have reviewed the Company's most recent three-year average of

1 rights-of-way mowing costs and found that the Company has never reported right-of-way
2 mowing as high as \$384,000. Hence adding \$384,431 to the amount recorded on its
3 books of \$55,479 in no way reflects a normalized level of these expenses. Moreover, the
4 Company has made an adjustment in the future test year to include an additional
5 \$100,000 for right-of-way mowing. The combined adjustment is excessive when
6 compared to the Company's recent history of these expenses. Therefore on Schedule
7 LKM-18, I have reduced O&M expenses by \$384,431.

8
9 **DOT Compliance Costs**

10 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REVERSE THE**
11 **COMPANY'S DEPARTMENT OF TRANSPORTATION (DOT)**
12 **COMPLIANCE COSTS CLAIM?**

13 A. The cost of service presented by Equitable includes an adjustment to increase O&M
14 expenses by \$133,524 for costs related to DOT compliance. Upon further investigation,
15 it was determined that these costs are those incurred to cathodically protect pipes.

16 Elsewhere in its filing, Equitable has indicated that it has changed its accounting
17 policy and now capitalizes cathodic protection costs. To be consistent with the
18 Company's accounting policies, these costs should be removed from O&M expenses.
19 Therefore, on Schedule LKM-19 I have removed the \$133,524 from the cost of service.

20 **Q. ON WHAT BASIS DO YOU CONCLUDE THAT THESE COSTS ARE**
21 **CAPITAL COSTS?**

22 A. In the Company's response to OCA VIII-6, Equitable explains that these costs are
23 associated with remediation of cathodically protected pipelines. Equitable states that
24 "[r]emedial work includes rehabilitation of existing cathodic protection systems, clearing
25 metallic shorts to foreign utility, restoring coating or repairing or renewing insulation

1 joints.” In the response to OCA VIII-8, Equitable states that “[r]ehabilitation of existing
2 cathodic protection system involves replacement of depleted anodes.” According to the
3 Company’s new accounting policy, replacement of anodes is to be capitalized. In
4 Equitable’s response to OCA I-19, the Company states that “all costs related to planned
5 replacement of anodes on a large scale across a significant pipeline segment shall be
6 capitalized.” Therefore, it appears that the costs associated with this 62.7-mile project
7 should be capitalized under the Company’s accounting policy.
8

9 **Universal Service Expenses**

10 **Q. WHY HAVE YOU ADJUSTED UNIVERSAL SERVICE EXPENSE?**

11 A. OCA witness Roger Colton has addressed the Company’s universal service program in
12 his direct testimony, and he determined that the Company overstated its projected
13 universal service costs b \$7,339,228. Based upon his recommendation, I have made an
14 adjustment that can be found on Schedule LKM-20 to reduce O&M expenses by the
15 overstated amount.
16

17 **Interest Synchronization**

18 **Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION**
19 **ADJUSTMENT.**

20 A. To determine the tax-deductible interest for ratemaking, I have multiplied the adjusted
21 rate base by the weighted cost of debt included in the capital structure. This procedure
22 synchronizes the interest deduction for tax purposes with the interest component of the
23 return on rate base to be recovered from ratepayers. As shown in Schedule LKM-21, this
24 adjustment increases the interest deduction by \$761,297 compared to the interest

1 deduction recognized by Equitable in its filing. This decreases state and federal income
2 taxes by \$76,054 and \$239,835 respectively.

3 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

4 A. Yes. However, I reserve the right to supplement this testimony to reflect any adjustments
5 deemed necessary once outstanding discovery responses are received from Equitable.

6
7
8 00104902.doc

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

EXHIBITS TO THE
DIRECT TESTIMONY OF
LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

OCTOBER 8, 2008

EXETER

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

EQUITABLE GAS COMPANY

Summary of Operating Income
For the Test Year Ended December 31, 2008

	PAPUC Jurisdictional Amount per Co.	OCA Cost of Service Adjustments	Amount After Adjustments	OCA Recommended Change In Revenue	After Proposed Revenue Change
<u>Operating Revenues</u>					
Total Operating Revenues	\$ 516,617,530	\$ 22,790,905	\$539,408,435	\$ (1,486,109)	\$ 537,922,326
<u>Operating Expenses</u>					
Purchased Gas Costs	\$ 359,315,773	\$ -	\$359,315,773	\$ -	\$ 359,315,773
Non-purchased Gas Costs	105,108,151	(13,512,777)	91,595,374	(31,448)	91,563,926
Depreciation & Amortization Expenses	23,471,055	-	23,471,055	-	23,471,055
Taxes Other Than Income	2,185,866	-	2,185,866	(4,096)	2,181,770
Current Federal Income Tax	(3,182,873)	11,197,097	8,014,224	(144,911)	7,869,313
Current State Income Tax	(1,009,313)	3,550,684	2,541,371	(456,979)	2,084,392
Deferred Federal Income Taxes	8,545,747	-	8,545,747	-	8,545,747
Investment Tax Credit	(5,529)	-	(5,529)	-	(5,529)
Total Operating Expenses	\$ 494,428,877	\$ 1,235,004	\$495,663,881	\$ (637,434)	\$ 495,026,447
Net Operating Income	\$ 22,188,653	\$ 21,555,901	\$ 43,744,554	\$ (848,675)	\$ 42,895,879
Rate Base	\$ 583,252,590		\$575,783,006		\$ 575,783,006
Return On Rate Base	3.80%		7.60%		7.45%

EQUITABLE GAS COMPANY

*Summary of Revenue Increase at OCA Rate of Return
For the Test Year Ended December 31, 2008*

	<u>Amount</u>	<u>Source</u>
Adjusted Rate Base	\$ 575,783,006	Schedule LKM-2, Page 2
Required Rate of Return	<u>7.450%</u>	
Net Operating Income Required	\$ 42,895,834	
Net Operating Income at Present Rates	<u>43,744,554</u>	Schedule LKM-1, Page 1
Income Deficiency/(Surplus)	\$ (848,720)	
Revenue Multiplier	<u>1.751</u>	
Required Change in Company Revenue	<u>\$ (1,486,109)</u>	
Proposed Revenue Change	\$ (1,486,109)	
Uncollectibles	1.920% (28,533)	
PUC, OCA, OSBA Assessments	0.281% (4,096)	
LIURP	0.200% <u>(2,915)</u>	
Subtotal	\$ (1,450,565)	
State Income Tax	9.99% <u>(144,911)</u>	
Subtotal	\$ (1,305,654)	
Federal Income Tax	35.00% <u>(456,979)</u>	
Net Income Increase Required	<u>\$ (848,675)</u>	

EQUITABLE GAS COMPANY

Summary of Rate Base
For the Test Year Ended December 31, 2008

	PAPUC Jurisdictional Amount per Co.	OCA Rate Base Adjustments	Amount After Adjustments
Total Plant in Service	\$ 897,954,727	\$ (1,761,627)	\$ 896,193,100
Accumulated Depreciation	(289,353,072)	-	(289,353,072)
Net Plant in Service	\$ 608,601,655	\$ (1,761,627)	\$ 606,840,028
<u>Additions:</u>			
Materials & Supplies	\$ 887,426	\$ -	\$ 887,426
Current Gas Storage	75,175,769	-	75,175,769
Cash Working Capital	11,335,335	(5,707,957)	5,627,378
Prepayments	234,270	-	234,270
Total Additions	\$ 87,632,800	\$ (5,707,957)	\$ 81,924,843
<u>Deductions:</u>			
Accumulated Deferred Income Taxes	\$(104,709,261)	\$ -	\$(104,709,261)
Income Tax Credits	(4,902,910)	-	(4,902,910)
Customer Advances	-	-	-
Customer Deposits	(3,369,694)	-	(3,369,694)
Total Deductions	\$(112,981,865)	\$ -	\$(112,981,865)
Total Rate Base	<u>\$ 583,252,590</u>	<u>\$ (7,469,584)</u>	<u>\$ 575,783,006</u>

EQUITABLE GAS COMPANY

Summary of Rate Base Adjustments
For the Test Year Ended December 31, 2008

	<u>Source</u>	<u>PAPUC Jurisdictional Amount per Co.</u>
Rate Base per Company Filing	Schedule LKM-2, Page 1	<u>\$ 583,252,590</u>
<u>OCA Adjustments:</u>		
Plant in Service		\$ (1,761,627)
Cash Working Capital		<u>(5,707,957)</u>
Total Ratemaking Adjustments		<u>\$ (7,469,584)</u>
Adjusted Rate Base per OCA		<u><u>\$ 575,783,006</u></u>

EQUITABLE GAS COMPANY

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2008

	Total Company Amount
Net Income per Company	<u>\$ 22,188,653</u>
<u>OCA Adjustments:</u>	
Annualize Operating Revenues	\$ 13,334,161
Reverse Company's Collection Cost Adjustment	358,178
Remove Excess Anode Expenses	157,767
Normalize Customer Experience Study Costs	372,503
Annualize PA One Call Expense	48,676
Remove Lobbying Expenses	72,310
Annualize Payroll Expenses	200,342
Reflect Ongoing Level of Pension & OPEB Costs	271,162
Normalize Regulatory Commission Expenses	174,806
Annualize the Increase in Cost of Fuel	40,734
Normalize Injuries & Damages Expense	1,612,411
Normalize Right of Way Mowing Expense	224,917
Reverse Cathodic Protection Costs	78,120
Universal Service Costs per OCA	4,293,925
Interest Synchronization	<u>315,889</u>
Total Ratemaking Adjustments	<u>\$ 21,555,901</u>
Total Adjusted Net Income per OCA	<u><u>\$ 43,744,554</u></u>

EQUITABLE GAS COMPANY

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2008

	Operating Revenues	O&M Expenses	Depreciation & Amortization Expenses	Taxes Other Than Income	Current State Income Tax	Current Federal Income Taxes	Deferred Income Taxes	Investment Tax Credit	Net Operating Income
PA Jurisdictional Amount per Company	\$ 516,617,530	\$464,423,924	\$ 23,471,055	\$ 2,185,866	\$ (1,009,313)	\$ (3,182,873)	\$ 8,545,747	\$ (5,529)	\$ 22,188,653
<u>OCA Adjustments</u>									
Annualize Operating Revenues	\$ 22,790,905	\$ -	\$ -	\$ -	\$ 2,276,811	\$ 7,179,933	\$ -	\$ -	\$ 13,334,161
Reverse Company's Collection Cost Adjustment	-	(612,202)	-	-	61,159	192,865	-	-	358,178
Remove Excess Anode Expenses	-	(269,658)	-	-	26,939	84,952	-	-	157,767
Normalize Customer Experience Study Costs	-	(836,686)	-	-	63,605	200,578	-	-	372,503
Annualize PA One Call Expense	-	(83,197)	-	-	8,311	26,210	-	-	48,676
Remove Lobbying Expenses	-	(123,593)	-	-	12,347	38,936	-	-	72,310
Annualize Payroll Expenses	-	(342,428)	-	-	34,209	107,877	-	-	200,342
Reflect Ongoing Level of Pension & OPEB Costs	-	(463,473)	-	-	46,301	146,010	-	-	271,162
Normalize Regulatory Commission Expenses	-	(298,781)	-	-	29,848	94,127	-	-	174,806
Annualize the Increase in Cost of Fuel	-	(69,623)	-	-	6,955	21,934	-	-	40,734
Normalize Injuries & Damages Expense	-	(2,755,953)	-	-	275,320	868,222	-	-	1,612,411
Normalize Right of Way Mowing Expense	-	(384,431)	-	-	38,405	121,109	-	-	224,917
Reverse Cathodic Protection Costs	-	(133,524)	-	-	13,339	42,065	-	-	78,120
Universal Service Costs per OCA	-	(7,339,228)	-	-	733,189	2,312,114	-	-	4,293,925
Interest Synchronization	-	-	-	-	(76,054)	(239,835)	-	-	315,889
Total Rate-making Adjustments	\$ 22,790,905	\$ (13,512,777)	\$ -	\$ -	\$ 3,550,684	\$ 11,197,097	\$ -	\$ -	\$ 21,555,901
Total Adjusted Income	\$ 539,408,435	\$450,911,147	\$ 23,471,055	\$ 2,185,866	\$ 2,541,371	\$ 8,014,224	\$ 8,545,747	\$ (5,529)	\$ 43,744,554

EQUITABLE GAS COMPANY

Reconciliation of Current State and Federal Income Taxes
For the Test Year Ended December 31, 2008

	Test Year Per Company	Ratemaking Adjustments	Test Year at Present Rates	Increase at OCA Rate of Return	After Proposed Revenue Change
CALCULATION OF COMBINED CURRENT INCOME TAX					
Net Operating Income Before Income Taxes	\$ 26,536,685	\$ 36,303,682	\$ 62,840,367	\$ (1,450,565)	\$ 61,389,802
<u>Adjustments for Income Taxes</u>					
Interest Expense	(16,972,820)	(761,297)	(17,734,117)	-	(17,734,117)
Book Depreciation Expense	23,471,055	-	23,471,055	-	23,471,055
Tax Depreciation Expense	(43,138,325)	-	(43,138,325)	-	(43,138,325)
State Taxable Income	\$ (10,103,405)	\$ 35,542,385	\$ (19,667,270)	\$ (1,450,565)	\$ (19,667,270)
State Income Tax	9.99% \$ (1,009,330)	\$ 3,550,684	\$ (1,964,760)	\$ (144,911)	\$ (1,964,760)
Federal Taxable Income Before State Income Tax	\$ (10,103,405)	\$ 35,542,385	\$ 25,438,980	\$ (1,450,565)	\$ 23,988,415
State Income Tax	(1,009,330)	3,550,684	2,541,354	(144,911)	2,396,443
Federal Taxable Income	\$ (9,094,075)	\$ 31,991,701	\$ 22,897,626	\$ (1,305,654)	\$ 21,591,972
Federal Income Tax	35.00% (3,182,926)	11,197,095	8,014,169	(456,979)	7,557,190
Federal Tax Credits	(5,529)	-	(5,529)	-	(5,529)
Net Federal Income Tax	\$ (3,188,455)	\$ 11,197,095	\$ 8,008,640	\$ (456,979)	\$ 7,551,661
Net Combined Current Income Tax	\$ (4,197,785)	\$ 14,747,779	\$ 10,549,994	\$ (601,890)	\$ 9,948,104
Total Combined Current Income Taxes (Schedule LKM-1, Page 1)	(4,197,715)	14,747,781	10,550,066	(601,890)	9,948,176
Unreconciled/Rounding	\$ (70)	\$ (2)	\$ (72)	\$ (0)	\$ (72)

EQUITABLE GAS COMPANY

Adjustment to Plant in Service
For the Test Year Ended December 31, 2008

	<u>Amount</u>
<u>Post-Test Year plant in Service</u>	
Purchase New Meters and Regulators	\$ 636,394 1/
Tools and Equipment	242,451 1/
PC and Laptop Replacement	141,000 1/
Automotive Replacements	<u>741,782 1/</u>
Total Adjustment to Plant in Service	<u><u>\$ 1,761,627</u></u>

Notes:

1/ Response to OCA IV-26.

EQUITABLE GAS COMPANY

Adjustment to Allowance for Cash Working Capital
For the Test Year Ended December 31, 2008

	Pro Forma Expenses	1/	OCA Adjustments	Adjusted Pro Forma Expenses	Daily Requirement	Revenue Lag Days	1/	Expense Lag days	1/	Net Lag Days	Working Capital Requirement
<u>Operating Expense</u>											
Purchased Gas	\$ 359,315,773		\$ -	\$ 359,315,773	\$ 984,427	49.29		45.91		3.38	\$ 3,327,363
Payroll	24,095,087		(263,467)	23,831,620	65,292	49.29		45.91	2/	3.38	220,701
Employee Benefits	7,069,423		(522,569)	6,546,854	17,937	49.29		17.20		32.09	575,535
Corporate Services	15,990,000		(122,009)	15,867,991	43,474	49.29		49.29		-	-
Injuries & Damages	4,803,788		(2,755,953)	2,047,835	5,611	49.29		(164.74)		214.03	1,200,922
Uncollectibles	25,049,825		(28,533)	25,021,292	68,551	49.29		49.29		-	-
Other O&M Expenses	28,100,026		(9,831,829)	18,268,197	50,050	49.29		36.84		12.45	623,307
	<u>\$ 464,423,922</u>			<u>\$ 450,899,562</u>							
Depreciation & Amortization	23,471,055		-	23,471,055	-						-
Taxes Other Than Income	2,185,866		(23,961)	2,161,905	5,923	49.29		(2.71)	3/	52.00	308,004
<u>Income Taxes</u>											
Current Federal	(3,182,873)		11,052,186	7,869,313	21,560	49.29		36.50		12.79	275,749
Current State	(1,009,313)		3,093,705	2,084,392	5,711	49.29		51.58		(2.29)	(13,077)
Deferred Federal & State	8,545,747		-	8,545,747	-						-
Investment Tax Credit	(5,529)		-	(5,529)	-						-
Interest on Debt	16,972,650		761,467	17,734,117	48,587	49.29		72.58		(23.29)	(1,131,582)
Sales and Use Taxes	6,287,006		-	6,287,006	17,225	49.29		35.33		13.96	240,456
											<u>\$ 5,627,378</u>
Cash Working Capital per OCA											11,335,335
Cash Working Capital per Company											<u>\$ (5,707,957)</u>
Adjustment to Cash Working Capital											

Notes:

1/ Exhibit VI, Item 18, page 2.

2/ Schedule LKM-5, page 3.

3/ Schedule LKM-5, page 10.

EQUITABLE GAS COMPANY

Calculation of Non-Union Payroll Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	1/ Lag Days	1/ Amount	1/ Dollar Days
12/18/06	12/31/06	12/24/06	01/10/07	16.50	\$ 663,113	\$ 10,941,365
01/01/07	01/14/07	01/07/07	01/24/07	16.50	663,604	10,949,466
01/01/06	12/31/06 2/	07/02/06	02/06/07	219.00	3,650,116 2/	799,375,404
01/15/07	01/28/07	01/21/07	02/07/07	16.50	665,254	10,976,691
01/29/07	02/11/07	02/04/07	02/21/07	16.50	656,666	10,834,989
02/12/07	02/25/07	02/18/07	03/07/07	16.50	650,454	10,732,491
02/26/07	03/11/07	03/04/07	03/21/07	16.50	682,704	11,264,616
03/12/07	03/25/07	03/18/07	04/04/07	16.50	658,826	10,870,629
03/26/07	04/08/07	04/01/07	04/18/07	16.50	657,239	10,844,444
04/09/07	04/22/07	04/15/07	05/02/07	16.50	663,850	10,953,525
04/23/07	05/06/07	04/29/07	05/16/07	16.50	669,857	11,052,641
05/07/07	05/20/07	05/13/07	05/30/07	16.50	664,132	10,958,178
05/21/07	06/03/07	05/27/07	06/13/07	16.50	666,519	10,997,564
06/04/07	06/17/07	06/10/07	06/27/07	16.50	663,067	10,940,606
06/18/07	07/01/07	06/24/07	07/11/07	16.50	664,892	10,970,718
07/02/07	07/15/07	07/08/07	07/25/07	16.50	662,533	10,931,795
07/16/07	07/29/07	07/22/07	08/08/07	16.50	649,673	10,719,605
07/30/07	08/12/07	08/05/07	08/22/07	16.50	648,531	10,700,762
08/13/07	08/26/07	08/19/07	09/05/07	16.50	635,798	10,490,667
08/27/07	09/09/07	09/02/07	09/19/07	16.50	640,692	10,571,418
09/10/07	09/23/07	09/16/07	10/03/07	16.50	591,651	9,762,242
09/24/07	10/07/07	09/30/07	10/17/07	16.50	593,444	9,791,826
10/08/07	10/21/07	10/14/07	10/31/07	16.50	596,533	9,842,795
10/22/07	11/04/07	10/28/07	11/14/07	16.50	598,294	9,871,851
11/05/07	11/18/07	11/11/07	11/28/07	16.50	590,987	9,751,286
11/19/07	12/02/07	11/25/07	12/12/07	16.50	629,265	10,382,873
12/03/07	12/16/07	12/09/07	12/26/07	16.50	589,239	9,722,444
				<u>52.79</u>	<u>\$ 20,366,933</u>	<u>\$ 1,075,202,885</u>

Notes:

1/ Exhibit VI, Item 18, page 11.

2/ Company response to OTS-RE-18-D.

EQUITABLE GAS COMPANY

Calculation of Union Payroll Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	1/ Lag Days	1/ Amount	1/ Dollar Days
12/18/06	12/31/06	12/24/06	01/12/07	18.50	\$ 393,762	\$ 7,284,597
01/01/07	01/14/07	01/07/07	01/26/07	18.50	386,120	7,143,220
01/01/06	12/31/06 2/	07/02/06	02/06/07	219.00	656,326	143,735,394
01/15/07	01/28/07	01/21/07	02/09/07	18.50	369,857	6,842,355
01/29/07	02/11/07	02/04/07	02/23/07	18.50	374,081	6,920,499
02/12/07	02/25/07	02/18/07	03/09/07	18.50	387,408	7,167,048
02/26/07	03/11/07	03/04/07	03/23/07	18.50	373,400	6,907,900
03/12/07	03/25/07	03/18/07	04/04/07	16.50	330,927	5,460,296
03/26/07	04/08/07	04/01/07	04/20/07	18.50	351,323	6,499,476
04/09/07	04/22/07	04/15/07	05/04/07	18.50	347,062	6,420,647
04/23/07	05/06/07	04/29/07	05/18/07	18.50	334,124	6,181,294
05/07/07	05/20/07	05/13/07	06/01/07	18.50	336,230	6,220,255
05/21/07	06/03/07	05/27/07	06/15/07	18.50	353,260	6,535,310
06/04/07	06/17/07	06/10/07	06/29/07	18.50	337,679	6,247,062
06/18/07	07/01/07	06/24/07	07/13/07	18.50	341,521	6,318,139
07/02/07	07/15/07	07/08/07	07/27/07	18.50	345,752	6,396,412
07/16/07	07/29/07	07/22/07	08/10/07	18.50	333,438	6,168,603
07/30/07	08/12/07	08/05/07	08/24/07	18.50	347,811	6,434,504
08/13/07	08/26/07	08/19/07	09/07/07	18.50	337,253	6,239,181
08/27/07	09/09/07	09/02/07	09/21/07	18.50	335,121	6,199,739
09/10/07	09/23/07	09/16/07	10/05/07	18.50	331,445	6,131,733
09/24/07	10/07/07	09/30/07	10/19/07	18.50	352,580	6,522,730
10/08/07	10/21/07	10/14/07	11/02/07	18.50	355,828	6,582,818
10/22/07	11/04/07	10/28/07	11/16/07	18.50	355,294	6,572,939
11/05/07	11/18/07	11/11/07	11/30/07	18.50	375,779	6,951,912
11/19/07	12/02/07	11/25/07	12/14/07	18.50	395,601	7,318,619
12/03/07	12/16/07	12/09/07	12/28/07	18.50	351,392	6,500,752
				31.74	\$ 9,890,374	\$ 313,903,428
Combined Payroll Amounts				45.91	\$ 30,257,307	\$ 1,389,106,313

Notes:

1/ Exhibit VI, Item 18, page 12.

EQUITABLE GAS COMPANY

Calculation of Corporate Services Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	Mid Point of Service Period	1/ Payment Date	Lag Days	2/ Amount	Dollar Days
01/01/07	01/31/07	01/16/07	n/a	49.29	\$ 1,311,496	\$ 64,643,638
02/01/07	02/28/07	02/14/07	n/a	49.29	1,354,246	66,750,785
03/01/07	03/31/07	03/16/07	n/a	49.29	1,354,246	66,750,785
04/01/07	04/30/07	04/15/07	n/a	49.29	1,354,246	66,750,785
05/01/07	05/31/07	05/16/07	n/a	49.29	1,354,246	66,750,785
06/01/07	06/30/07	06/15/07	n/a	49.29	1,267,733	62,486,560
07/01/07	07/31/07	07/16/07	n/a	49.29	1,354,246	66,750,785
08/01/07	08/31/07	08/16/07	n/a	49.29	1,354,246	66,750,785
09/01/07	09/30/07	09/15/07	n/a	49.29	1,331,410	65,625,199
10/01/07	10/31/07	10/16/07	n/a	49.29	1,354,246	66,750,785
11/01/07	11/30/07	11/15/07	n/a	49.29	1,354,246	66,750,785
12/01/07	12/31/07	12/16/07	n/a	49.29	1,449,883	71,464,733
				<u>49.29</u>	<u>\$ 16,194,490</u>	<u>\$ 798,226,412</u>

Notes:

1/ Exhibit VI, Item 18, page 13.

2/ Revenue Lag presented on Exhibit VI, Item 18, page 2.

EQUITABLE GAS COMPANY

Calculation of Other O&M-Goods & Services Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u>	<u>Amount</u> 1/	<u>Dollar Days</u> 1/
Other O&M Totals		\$ 3,568,382	\$ 100,655,431
Other Goods & Services Totals		11,640,164	399,128,278
OSS - NCO Totals		2,794,637	151,981,995
OSS - Trafford Totals		1,741,825	79,604,796
OSS - HEATH Consultants Totals		1,192,201	44,544,821
C. Leon Sherman & Associates		498,255	20,827,565
Pittsburgh Mailing & ADS		<u>848,033</u>	<u>24,098,883</u>
Other O&M Totals		<u>\$ 22,283,497</u>	<u>\$ 820,841,769</u>
Other O&M Lag Days	<u>36.84</u>		

Notes:

1/ Exhibit VI, Item 18, pages 14 - 18.

2/ Schedule LKM-6, Page 6.

EQUITABLE GAS COMPANY

Calculation of Other O&M-C. Leon Sherman Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/	Payroll Period End	1/	Mid Point of Service Period	1/	Payment Date	1/	Lag Days	1/	Amount	1/	Dollar Days
12/01/06		12/31/06		12/16/06		01/30/07		45.00		\$ 87,651		\$ 3,944,295
01/01/07		01/31/07		01/16/07		03/01/07		44.00		76,761		3,377,484
02/01/07		02/28/07		02/14/07		03/20/07		33.50		57,826		1,937,171
04/01/07		04/30/07		04/15/07		05/22/07		36.50		155,913		5,690,825
05/01/07		05/31/07		05/16/07		06/28/07		43.00		15,191		653,213
06/01/07		06/30/07		06/15/07		07/24/07 2/		38.50		7,479		287,942
07/01/07		07/31/07		07/16/07		08/28/07		43.00		24,015		1,032,645
09/01/07		09/30/07		09/15/07		10/04/07		18.50		9,285		171,773
09/01/07		09/30/07		09/15/07		11/13/07		58.50		24,893		1,456,241
10/01/07		10/31/07		10/16/07		12/13/07		58.00		39,241		2,275,978
								41.80		\$ 498,255		\$ 20,827,565

Notes:

1/ Exhibit VI, Item 18, pages 15 - 18.

2/ Response to OTS-RE-23-D.

EQUITABLE GAS COMPANY

Calculation of Pensions & Benefits Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u>	<u>1/</u>	<u>Amount</u>	<u>1/</u>	<u>Dollar Days</u>
Total 401(k) Match & Retirement Contribution			\$ 1,945,742	2/	\$ 32,381,154
Total 401(k) Administration Fees			1,398		127,849
Total ESPP Discount			26,607		557,948
Total ESPP Administration Fees			15,813		1,821,280
Total HSA Company Contribution			162,250		(28,356,500)
Total HSA Account Fees			8,232		72,322
Total Health Claims, Admin & Enrollment Fees			2,736,530		24,628,772
Total Active Vision			61,489		2,435,075
Total Executive Health Care Exams			9,225	3/	-
Total Active Life, AD&D, LTD			182,935		7,197,330
Total Active Dental			242,987		7,766,042
Total Employee Assistance Program			14,770		140,129
Total Aon Admin Fees			148,394		13,680,486
Retirees Pensions & Benefits Totals			3,446,372		92,426,848
Pension & Benefit Totals			<u>\$ 9,002,744</u>		<u>\$ 154,878,735</u>
Pension & Benefits Lag Days	<u>17.20</u>				

Notes:

1/ Exhibit VI, Item 18, pages 20 - 27.

2/ Schedule LKM-6, page 8.

3/ Schedule LKM-6, Page 9.

EQUITABLE GAS COMPANY

Calculation of 401(k) Match & Retirement Contribution Lag
For the Test Year Ended December 31, 2008

	<u>Payroll Period Begin</u>	<u>Payroll Period End</u>	<u>Mid Point of Service Period</u>	<u>Payment Date</u>	<u>Lag Days</u>	<u>Amount</u>	<u>Dollar Days</u>
<u>401(k) Match & Retirement Contribution</u>							
Total Per Company						\$ 1,945,742 1/	\$ 32,104,741 1/
Bonus Contribution per Co.	01/14/07 1/	01/27/07 1/	01/20/07 1/	02/06/07 1/	16.50 1/	(1,365) 1/	(22,523) 1/
Bonus Contribution per OCA	01/01/06	12/31/06	07/02/06	02/06/07	219.00 2/	<u>1,365</u>	<u>298,935</u>
Total 401(k) Match & Retirement Contribution Per OCA					16.64	<u><u>1,945,742</u></u>	<u><u>32,381,154</u></u>

Notes:

1/ Exhibit VI, Item 18, page

2/ Based on the response to OTS-RE-18-D.

EQUITABLE GAS COMPANY

Calculation of Executive Health Care Exams Lag
For the Test Year Ended December 31, 2008

<u>Payroll Period Begin</u>	<u>Payroll Period End</u>	<u>Mid Point of Service Period</u>	<u>Payment Date</u> 1/	<u>Lag Days</u>	<u>Amount</u> 1/	<u>Dollar Days</u>
<u>Executive Health Exams</u>						
01/04/07 2/	01/04/07 2/	01/04/07	01/04/07	0.00	\$ 1,825	\$ -
03/06/07 2/	03/06/07 2/	03/06/07	03/06/07	0.00	3,650	-
03/15/07 2/	03/15/07 2/	03/15/07	03/15/07	0.00	1,825	-
08/02/07 2/	08/02/07 2/	08/02/07	08/02/07	0.00	1,925	-
Totals				<u>0.00</u>	<u>\$ 9,225</u>	<u>\$ -</u>

Notes:

1/ Exhibit VI, Item 18, page 23.

2/ Response to OCA I-50.

EQUITABLE GAS COMPANY

Calculation of Taxes Other Than Income Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u>	<u>Amount</u>	<u>Dollar Days</u>
Combined Taxes Other Than Income Amounts Per Company		\$ 1,394,466 2/	\$ (92,099,751) 2/
Payroll Taxes	45.91 1/	1,816,490 3/	83,394,657 4/
Combined Taxes Other Than Income Amounts	<u>(2.71)</u>	<u>\$ 3,210,956</u>	<u>\$ (8,705,094)</u>

Notes:

- 1/ Exhibit VI, Item 18, page 12.
2/ Exhibit VI, Item 18, page 31.
3/ Exhibit III, Item § 53.53 III.A.17, Sheet 6.
4/ Lag days x Amount.

EQUITABLE GAS COMPANY

Adjustment to Annualize Operating Revenues
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Annualize Operating Revenues	<u>\$ 22,790,905 1/</u>
Adjustment to Operating Revenues	<u><u>\$ 22,790,905</u></u>

Notes:

1/ Adjustment Recommended by OCA Witness Glen Watkins.

EQUITABLE GAS COMPANY

Adjustment to Reverse Company's Adjustment to Include
Collection Costs in O&M Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Collection Costs Included in the Cost of Service	<u>\$ 612,202</u> 1/
Adjustment to O&M Expenses	<u><u>\$ (612,202)</u></u>

Notes:

1/ Exhibit III, Item § 53.53 III.A.17, Page 9.

EQUITABLE GAS COMPANY

Adjustment to Remove Excess Anode Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Excess Anode Expenses	<u>\$ 269,658 1/</u>
Adjustment to O&M Expenses	<u><u>\$ (269,658)</u></u>

Notes:

1/ Response to OCA I-19.

EQUITABLE GAS COMPANY

Adjustment to Normalize Customer Experience Study Costs
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Customer Experience Study Costs	\$ 795,858 1/
Normalization Period (Years)	<u>5</u>
Normalized Customer Experience Study Costs	\$ 159,172
Customer Experience Study Costs per Company	<u>795,858</u>
Adjustment to O&M Expenses	<u><u>\$ (636,686)</u></u>

Notes:

1/ Response to OCA I-26.

EQUITABLE GAS COMPANY

Adjustment to Annualize PA One Call Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Annulized PA One Call Expense	\$ 488,986 1/
Annulized PA One Call Expense per Company	<u>572,183</u>
Adjustment to O&M Expenses	<u><u>\$ (83,197)</u></u>

Notes:

1/ Response to OCA I-20.

EQUITABLE GAS COMPANY

Adjustment to Remove Lobbying Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Lobbying Expenses Included in Corporate Allocation	\$ (122,009) 1/
Portion of AGA Dues Attributed to Lobbying	<u>(1,584) 2/</u>
Adjustment to O&M Expenses	<u>\$ (123,593)</u>

Notes:

1/ Response to OTS-RE-78-D.

2/ Exhibit VI, Standard Data Request, Volume 1, Item No.33.

EQUITABLE GAS COMPANY

Adjustment to Annualize Payroll Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
<u>Payroll Expenses</u>	
<u>Unfilled Positions</u>	
Compression Operator	\$ 45,531 1/
Compression Operator	45,531 1/
Producer Services Analyst	39,967 1/
Producer Services Engineer	65,000 1/
<u>Vacated Positions</u>	
Position # 99909180	<u>67,438 2/</u>
Adjustment to Payroll Expenses	<u>\$ (263,467)</u>
<u>Fringe Benefits Expenses</u>	
Total Fringe Benefits Percentage	29.97%
Total Decrease in Fringe Benefits Expenses	<u>\$ (78,961)</u>
 Adjustment to O&M Expenses	 <u><u>\$ (342,428)</u></u>

Notes:

1/ Response to OCA I-11.

2/ Responses to OCA IX-8 and OCA I-8.

EQUITABLE GAS COMPANY

Adjustment to Reflect Pension & Postretirement Benefits at the Ongoing Level
For the Test Year Ended December 31, 2008

	<u>Amount</u>
2008 Total Pension Cost	\$ 594,491 1/
2008 Total Postretirement Benefits Cost	<u>1,807,247 1/</u>
Total Pension & Postretirement Benefits Costs	\$ -2,401,738
Pennsylvania Percentage	<u>98.36% 2/</u>
Pennsylvania Pension & Postretirement Benefits Costs	\$ 2,362,349
O&M Percentage	<u>84.40%</u>
Pennsylvania Pension & Postretirement Benefits Expense	\$ 1,993,823 3/
PA Pension & Postretirement Benefits Expense per Company	<u>2,457,296 4/</u>
Adjustment to O&M Expenses	<u><u>\$ (463,473)</u></u>

Notes:

1/ Response to OTS-RE-68-D.

2/ Standard Data Requests, Item 23.

3/ Standard Data Requests, Item 19.

4/ Response to OTS-RE-139-D.

EQUITABLE GAS COMPANY

**Adjustment to Normalize Regulatory Commission Expenses
For the Test Year Ended December 31, 2008**

	<u>Amount</u>
Cost of the Current Rate Case	\$ 1,051,160 1/
Cost of the Service Life Study	<u>15,000 2/</u>
Total Rate Case	\$ 1,066,160
Normalization Period (Years)	<u>5</u>
Normalized Rate Case Expenses	\$ 213,232
Historical Test Year Regulatory Expenses	13,474 3/
Costs Related to West Virginia Matters	<u>(8,626) 4/</u>
Future Test Year Regulatory Expenses per OCA	\$ 218,080
Future Test Year Regulatory Expenses per Company	<u>516,861</u>
Adjustment to O&M Expenses	<u><u>\$ (298,781)</u></u>

Notes:

1/ Exhibit III, Item § 53.53 III.A.20 Sheet 2.

2/ Per OTS-RE-89-D, the total cost of the management audit and the service life study is \$765,000, and OCA IV-15 the management audit cost is \$750,000.

3/ Exhibit III, Item § 53.53 III.A.28 Sheet 7.

4/ Per response to OCA IV-8.

EQUITABLE GAS COMPANY

Adjustment to Annualize the Increase in Cost of Fuel
For the Test Year Ended December 31, 2008

	Diesel Gallons		Gasoline Gallons		Totals
January 2008 - August 2008 Fuel Usage	57,247	1/	178,709	1/	
Period Number of Months	8		8		
Annual Number of Months	<u>12</u>		<u>12</u>		
Annualized 2008 Fuel Usage	85,871		268,064		
2008 Price per Gallon	<u>\$ 4.00</u>	2/	<u>\$ 3.61</u>	2/	
Annualized Fuel Expense	\$ 343,482		\$ 967,709		\$ 1,311,191
Annualized Fuel Expense per Company	<u>392,391</u>	2/	<u>988,423</u>	2/	<u>1,380,814</u>
Adjustment to O&M Expenses	<u>\$ (48,909)</u>		<u>\$ (20,714)</u>		<u>\$ (69,623)</u>

Notes:

1/ Response to OCA VIII-18.

2/ Response to OCA I-17.

EQUITABLE GAS COMPANY

Adjustment to Normalize Injuries & Damages Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>	<u>Totals</u>
<u>Charges Against the Reserve (Claims)</u>		
2005 Charges Against the Reserve	\$ 235,769 1/	
2006 Charges Against the Reserve	256,243 1/	
2007 Charges Against the Reserve	<u>363,135 1/</u>	
Average		\$ 285,049
<u>Test Year Expense</u>		
2007 Expense Accrual	\$ 2,888,475 1/	
2007 Reserve Adjustments	(2,992,765) 1/	
Company's Pro Forma Normalization Adjustment	<u>3,145,292 1/</u>	
Net Injuries & Damages Expense		<u>3,041,002</u>
Adjustment to O&M Expenses		<u><u>\$(2,755,953)</u></u>

Notes:

1/ Response to OCA I-1.

EQUITABLE GAS COMPANY

Adjustment to Normalize Right of Way Mowing Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Customer Experience Study Costs	<u>\$ 384,431 1/</u>
Adjustment to O&M Expenses	<u><u>\$ (384,431)</u></u>

Notes:

1/ Response to OCA I-26.

EQUITABLE GAS COMPANY

Adjustment to Reverse Cathodic Protection Costs Related to DOT Compliance
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Cathodic Protection Costs,	<u>\$ 133,524</u> 1/
Adjustment to O&M Expenses	<u><u>\$ (133,524)</u></u>

Notes:

1/ Response to OCA I-4.

EQUITABLE GAS COMPANY

Adjustment to Reflect OCA's Universal Service Costs adjustments
For the Test Year Ended December 31, 2008

	<u>Amount</u>	<u>1/</u>
Total Universal Service Adjustments per OCA		
Witness Colton	\$ 9,236,270	
CAP Administrative Costs	<u>299,194</u>	
Total Universal Service and Administrative		
Costs per OCA	\$ 9,535,464	
Total Universal Service and Administrative		
Costs per Company	<u>16,874,692</u>	
Adjustment to O&M Expenses	<u>\$ (7,339,228)</u>	

Notes:

1/ Schedule RDC-5.

EQUITABLE GAS COMPANY

Interest Synchronization Adjustment
For the Test Year Ended December 31, 2008

	<u>Amount</u>
OCA Rate Base	\$ 575,783,006 1/
Weighted Cost of Debt	<u>3.08%</u>
Adjusted Interest Deduction	\$ 17,734,117
Interest Deduction Per Company	<u>16,972,820 2/</u>
Adjustment to Synchronize Interest Expense	\$ 761,297
Effective State Income Tax Rate	<u>9.99%</u>
Adjustment to State Income Taxes	<u>\$ (76,054)</u>
Federal Income Tax Base	\$685,243
Federal Income Tax Rate	<u>35.00%</u>
Adjustment to Federal Income Taxes	<u>\$ (239,835)</u>

Notes:

1/ Schedule LKM-2, Page 1.

2/ Exhibit III, Item § 53.53 III.A.17, Sheet 8.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08
NBG, PA
P45

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

DIRECT TESTIMONY OF
LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

OCTOBER 8, 2008

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

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Introduction and Summary

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. I am a Senior Regulatory Analyst with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Business Administration degree from The George Washington University. The major area of concentration for this degree was Finance. I received a Bachelor of Business Administration degree with concentration in Accounting from North Carolina Central University. I am also a Certified Public Accountant licensed in the State of North Carolina.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From May 1984 until June 1990, I was employed by the North Carolina Utilities Commission - Public Staff in Raleigh, North Carolina. I was responsible for analyzing testimony, exhibits, and other data presented by parties before the North Carolina Utilities Commission. I had the additional responsibility of performing the examinations of books and records of utilities involved in rate proceedings and summarizing the results into testimony and exhibits for presentation before that Commission. I was also involved in numerous special projects, including participating in compliance and prudence audits of a major utility and conducting research on several issues affecting natural gas and electric utilities.

1 From June 1990 until July 1993, I was employed by Potomac Electric Power
2 Company (Pepco) in Washington, D.C. At Pepco, I was involved in the preparation of
3 the cost of service, rate base and ratemaking adjustments supporting the company's
4 requests for revenue increases in the State of Maryland and the District of Columbia.
5 I also conducted research on several issues affecting the electric utility industry for
6 presentation to management.

7 In July 1993, I accepted my current position with Exeter Associates, Inc. Since
8 then, I have been involved in the analysis of the operations of public utilities, with
9 particular emphasis on utility rate regulation. I have also been involved in the review and
10 analysis of utility rate filings, focusing primarily on revenue requirements determination.
11 This work has involved natural gas, water, electric and telephone companies.

12 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY**
13 **PROCEEDINGS ON UTILITY RATES?**

14 A. Yes. I have previously presented testimony and affidavits on numerous occasions before
15 the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission,
16 the Virginia Corporation Commission, the Louisiana Public Service Commission, the
17 Georgia Public Service Commission, the Maine Public Utilities Commission, the
18 Kentucky Public Service Commission, the Public Utilities Commission of Rhode Island,
19 the Vermont Public Service Board, the Illinois Commerce Commission and the Federal
20 Energy Regulatory Commission (FERC).

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

23 A. Exeter Associates has been retained by the Office of Consumer Advocate (OCA) to
24 review the reasonableness of the level of revenues which Equitable Gas Company
25 (Equitable or the Company) is proposing to charge its customers. In this testimony,

1 I present my findings on behalf of the OCA regarding certain adjustments to Equitable's
2 future test year rate base and net operating income at present rates. In addition, I also
3 present a summary of the OCA's findings regarding the current levels of Equitable's
4 earnings and determine the necessary change in its revenues that is required to produce an
5 overall rate of return on rate base of 7.46 percent. This return is based on the
6 recommendation of OCA witness David Parcell.

7 **Q. IN CONNECTION WITH THIS CASE, HAVE YOU PERFORMED AN**
8 **EXAMINATION AND REVIEW OF THE COMPANY'S TESTIMONY**
9 **AND EXHIBITS?**

10 A. Yes. I have reviewed Equitable's testimony and exhibits, its rate filing, as well as its
11 responses to the OCA's and other parties' data requests.

12 **Q. WOULD YOU PLEASE SUMMARIZE WHAT IS PRESENTED ON THE**
13 **ATTACHED SCHEDULES?**

14 A. Yes. I have prepared a set of schedules that present my findings and recommendations
15 regarding the Company's rate base and net operating income. Schedule LKM-1
16 summarizes my overall findings regarding net operating income. Schedule LKM-2
17 presents a summary of rate base and my adjustments thereto. Schedule LKM-3
18 summarizes each of my adjustments to Equitable's net income. Schedule LKM-4
19 presents a reconciliation of current income taxes. The remaining schedules show the
20 derivation of each of my adjustments to rate base and net operating income.

21 **Q. PLEASE SUMMARIZE YOUR FINDINGS.**

22 A. I have determined the appropriate change in Equitable's distribution revenues to be a
23 \$29.4 million increase as compared to the Company's request of \$51.9 million. This
24 revenue change is based on the level of rate base and cost of service that I am
25 recommending and Mr. Parcells' rate of return recommendation. When the cost of

A. service is adjusted to correct for the overstatement of the universal service costs as recommended by OCA witness Roger Colton, the revenue requirement increase is \$18.7 million. When the disallowance of the negotiated rate discounts as recommended by OCA witness Glenn Watkins is reflected, the OCA's recommended change in revenues would be a decrease of \$4.6 million. This represents a reduction of \$56.5 million in the Company's requested distribution revenue increase.

The OCA recommended distribution revenue change would result in a 0.28 percent decrease in distribution revenue instead of 10.0 percent proposed by the Company. The chart below summarizes the adjustments I am recommending:

Description	Rate Base	Revenues	O&M Expenses
Post Test Year Plant in Service	\$(1,761,629)	\$	\$
Cash Working Capital	(5,785,973)		
Operating Revenues		22,790,905	
Lobbying Expenses			(123,593)
Regulatory Commission Expense			(298,781)
Collection Costs			(612,202)
Anode Expenses			(269,658)
Customer Experience Expenses			(636,686)
PA One Call Expenses			(83,197)
Fuel Expenses			(69,623)
Injuries & Damages Expense			(2,755,953)
Right-of-Way Mowing Expense			(384,431)
Cathodic Protection			(133,524)
Postretirement and Pension Expense			(463,473)
Payroll Expense			(342,428)
Universal Service			(7,339,228)

Q. WHAT TIME PERIOD DID YOU USE IN YOUR ANALYSIS OF THE COMPANY'S OPERATING RESULTS?

A. The Company's filing includes revenue requirement analyses based upon both a historical test year ended December 31, 2007 and a future test year ending December 31, 2008. I have based my analysis of the Company's operating results on the future test year

1 A. ending December 31, 2008. This is the same period used by the Company to determine
2 its requested rate increase in its rate filing, direct testimony and exhibits.

3 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

4 A. The remainder of this testimony addresses each of the adjustments that I am
5 recommending and is presented in the order identified in the table of contents to this
6 testimony. For each issue, I will document and explain why it was necessary to make the
7 adjustment.

8
9 **Rate Base Adjustments**

10 **Plant in Service**

11 Q. WHAT ADJUSTMENTS ARE YOU RECOMMENDING BE MADE TO
12 PLANT IN SERVICE?

13 A. Equitable has made a claim in the future test year to include Construction Work In
14 Progress (CWIP) that it claims will be completed and placed in service within six months
15 after the end of the future test year. Some of the projects that Equitable has included as
16 CWIP are actually stand alone assets that will be acquired within six months after the end
17 of the future test year. Unlike CWIP, stand alone assets are not projects that require
18 construction to develop the final asset that is placed in service. For the most part, stand
19 alone assets can be placed in service almost immediately after acquisition. As a result,
20 they are not projects that existed at the end of the future test year. Instead, they are
21 expenditures that are projected to be made after the end of the test year. As a result, the
22 inclusion of these costs in plant in service is not consistent with the Commission's
23 practice of recognizing non-revenue producing CWIP that existed as of the end of the
24 future test year as being eligible for rate base inclusion.

1 Since the stand alone assets are not in accordance with Commission practice, I am
2 recommending an adjustment that removes the cost of these assets of \$1,761,627 from
3 the future test year plant in service on Schedule LKM-5. This adjustment brings the
4 Company's plant in service into compliance with Commission practice.

5 **Q. DOES YOUR ADJUSTMENT TO RECOGNIZE NON-REVENUE**
6 **PRODUCING CWIP INDICATE YOU BELIEVE RECOGNIZING CWIP**
7 **IS APPROPRIATE?**

8 A. No. CWIP does not represent plant that is used and useful as of the end of the test year.

9 In addition, including CWIP results in a mismatch among the elements of rate base
10 because it fails to recognize that depreciation and deferred taxes will continue to accrue
11 during the time period that the CWIP is being completed and placed in service. Finally,
12 including CWIP in rate base results in a mismatch between revenues, expenses and rate
13 base. However, I recognize that the Commission has traditionally allowed the inclusion
14 of non-revenue producing and non-expense reducing CWIP, which will be placed in
15 service within six months of the end of the test year, to be included in rate base.
16 Accordingly, I have made this adjustment to be consistent with Commission practice.

17
18 **Allowance for Cash Working Capital**

19 **Q. HOW DO YOU DEFINE CASH WORKING CAPITAL?**

20 A. For ratemaking purposes, cash working capital is the investment that a utility needs to
21 have on hand to fund its day-to-day operations. Positive cash working capital represents
22 funds provided by investors that should be included in rate base so that the Company
23 earns a return on it. Negative cash working capital represents funds supplied by
24 ratepayers that should be recognized as a rate base offset.

1 **Q. HOW DID THE COMPANY REFLECT CASH WORKING CAPITAL IN**
2 **ITS FILING?**

3 A. The Company's cash working capital allowance is calculated based upon the results of a
4 lead-lag study. A lead-lag study is an in-depth analysis that measures the difference
5 between the lapse of time when the Company receives revenue for the provision of
6 service and the lapse of time when the Company pays for the costs of providing service.
7 This difference, expressed as a number of days, is used to calculate the level of investor-
8 supplied funds advanced for operations if the difference is positive. If the difference is
9 negative, it is used to calculate the funds advanced by customers.

10 The revenue lag represents the average number of days from the date on which
11 service is provided to the customers until the date on which payment is received from the
12 customers. It is measured from the midpoint of the service period covered by the bill to
13 the date payment for that service is received by the Company. The Company's expense
14 lag, or payment lag, represents the average number of days from the date the expense is
15 incurred in rendering service until the date the expense is paid. It is also measured from
16 the midpoint of the service period to the date the expense is paid.

17 After both the Company's revenue lag and expense payment lag have been
18 determined, one can make a reasonable approximation of the Company's cash working
19 capital requirement. This calculation is made by dividing the expenses by 365 days to
20 determine the average daily amount. The average daily amount is multiplied by the net
21 lead-lag days (the difference from subtracting the expense lag from the revenue lag) to
22 derive the Company's working capital requirements. If the total working capital
23 requirement is positive, it represents a level of funds that must be included in rate base so
24 that the Company is provided a return on the funds supplied by investors. Conversely, if

1 the amount is negative, then the amount reduces rate base to recognize funds that
2 customers have advanced.

3 **Q. PLEASE DEFINE THE TERMS "LEAD" AND "LAG" AS YOU USE**
4 **THEM IN YOUR TESTIMONY.**

5 A. The term "lead" is used to indicate either the receipt of revenue prior to the date that
6 service is provided or the payment of an expense prior to the date that the expense is
7 incurred. The term "lag" is used to indicate either the receipt of revenue after the date
8 that service is provided or the payment of an expense after the date that the expense is
9 incurred.

10 **Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE ALLOWANCE**
11 **FOR CASH WORKING CAPITAL?**

12 A. I have reviewed the supporting documentation for the lead-lag study and disagree with
13 the determination of the lead-lag days attributed to certain components of the lead-lag
14 study. I have made corrections to the components as necessary, and will discuss each of
15 these corrections.

16 **Q. WHAT IS THE FIRST CORRECTION THAT YOU MADE TO THE**
17 **LEAD-LAG STUDY?**

18 A. The first correction I have made to the lead-lag study involves the lag days assigned to
19 the short-term incentive compensation paid to both union and non-union employees. The
20 short-term incentive compensation is paid based upon achieving certain corporate and
21 individual goals annually. If the goals have been achieved by the end of the current year,
22 the incentive compensation is paid to eligible employees in the following year. The fact
23 that the incentive compensation is paid in the year following the current year is not
24 reflected in the company's lag day calculation. This is wrong because the payment lag
25 days should reflect the actual period over which the service was performed. This error

1 causes an increase in the cash working capital. Specifically, the short-term incentive
2 compensation earned during 2006 was paid on February 6, 2007. The Company
3 calculated the service period as if it were earned during the period January 14, 2007
4 through January 23, 2007 instead of the period over which it was earned (January 1, 2006
5 through December 31, 2006). The service period used by the Company grossly distorts
6 the short-term incentive plan payment lag because it treats the incentive compensation as
7 if it was earned in the previous two weeks rather than the previous year. Therefore, I
8 have corrected the payment lag days to reflect the actual period over which the short-term
9 incentive compensation was earned. On Schedule LKM-6, pages 2 and 3, I present the
10 recalculation of the payroll lag for union and non-union employees. In addition to
11 correcting the service period to reflect the actual service period for the short-term
12 incentive compensation, I have also corrected the non-union short-term incentive
13 compensation amount to remove an error made by the Company. In the response to
14 OTS-RE-18-D, Equitable indicated that the correct short-term incentive compensation
15 amount paid was \$3,650,116 instead of the \$3,557,439 that was used in cash working
16 capital supporting documentation.

17 **Q. ARE THERE ANY OTHER COSTS IN THE LEAD-LAG STUDY THAT**
18 **ARE AFFECTED BY THE SHORT-TERM INCENTIVE**
19 **COMPENSATION SERVICE PERIOD?**

20 A. Yes. The short-term incentive compensation service period affects the lag on the 401(k)
21 matching costs and the payroll tax lag. The Company's 401(k) matching contribution is
22 based upon a percentage of the payroll. Whenever there is a payroll payment, there is a
23 corresponding 401(k) matching contribution. Hence, just as there is an additional pay
24 period for the short-term incentive compensation, there is a corresponding 401(k)
25 matching contribution. Equitable calculated the 401(k) matching as if it was earned in

1 the previous two weeks. As I explain in my discussion of the short-term incentive
2 compensation lag, this is wrong. Therefore, on Schedule LKM-6, page 3 I have shown
3 the correction of the 401(k) matching lag days to reflect the actual service period (the
4 previous year) over which the 401(k) related to the incentive compensation was earned.
5 This service period is the same as the service period I used to calculate the short-term
6 incentive compensation payment lag.

7 The other costs that are affected by the short-term incentive plan service period
8 are payroll taxes. Equitable explains in its filing that payroll taxes are paid at the same
9 time the payroll is paid. Accordingly, Equitable's payroll taxes lag is the same as its
10 payroll lag. As a result of the correction in the payroll lag that I have made, there is a
11 corresponding change in the payroll taxes lag. I have presented this change on Schedule
12 LKM-6, page 10.

13 **Q. PLEASE EXPLAIN THE NEXT CORRECTION THAT YOU HAVE**
14 **MADE TO THE COMPANY'S LEAD LAG STUDY.**

15 A. The next correction I have made to Equitable's lead-lag study involves the Corporate
16 Services lag. Corporate Services expenses are Equitable's share of costs that it receives
17 through charges from its parent company and affiliates. In the lead-lag workpapers, the
18 Company calculates the lag days on Corporate Services as if it is paid on the last day of
19 each month. In 8 of the 12 months presented, the costs are exactly the same. Therefore,
20 it appears that the bills could not have been the actual costs incurred during the month,
21 and that it is not likely to have been paid on the last day of the month since the company
22 has to go through the month-end closing to formally determine the costs. Month-end
23 closing usually takes a few days to complete, so the amount the Company claims to have
24 paid on the last day could not be the actual closed costs. Moreover, the use of the same
25 amount in those eight months indicates that the amount is an estimate, not the actual

1 amount, because the Company should be charged based upon actual activity during the
2 month. The monthly activity generally varies from month to month.

3 In the response to OCA I-45, Equitable stated that it does not, in fact, receive a
4 bill from corporate services and that no cash payments are actually made. This means
5 that the costs recorded on Equitable's books are essentially settled through accounting
6 entries. However, the calculation presented by the Company presents the costs as if there
7 is a cash payment on average approximately 15 days from the mid-point of the service
8 period. This time period is not an accurate portrayal of settlement of the costs.
9 Therefore, I have corrected the lag on corporate services by using the revenue lag days
10 instead of the Company's assumption. The use of revenue lag days is appropriate
11 because it reflects how the account actually is settled. By using the revenue lag, the costs
12 are treated as being paid as collected and results in having no net effect on working
13 capital. This treatment is consistent with the fact that no cash is exchanged in payment of
14 these costs and with the Company's treatment of uncollectibles, which is also a non-cash
15 expense. I have shown this calculation on Schedule LKM-6, page 4.

16 **Q. WHAT IS THE NEXT CORRECTION YOU HAVE MADE?**

17 A. The next correction I made is to the Other Expense lag. In the response to OTS-RE-23-
18 D, the Company indicated that there was an error in one of the payment dates given for
19 one of its vendors, C. Leon Sherman & Associates PC. I have corrected the lag days to
20 reflect the correct payment date for that vendor as provided by Equitable. The corrected
21 lag day calculation is presented on Schedule LKM-6, pages 5 and 6.

22 **Q. WOULD YOU EXPLAIN YOUR NEXT CORRECTION TO THE CASH**
23 **WORKING CAPITAL?**

24 A. Yes. The next correction I made is to the pension and benefits lag days. The change in
25 the lag days is the result of corrections to two components of costs in that category. The

1 first component is the lag days for the 401(k) matching contribution that I have explained
2 was caused by the correction of the short-term incentive compensation service period
3 from the previous two weeks to the previous year.

4 The second component is the service period used for executive health exams.
5 In the Company's workpapers, Equitable incorrectly calculates the lag days based upon a
6 service that begins on January 1, 2007, and extends through December 31, 2007.
7 According to the response to OTS-RE-30-D, each of the qualified individuals is offered
8 one health exam annually at Company expense. Each of the health exams occurred on
9 specific dates for each of the individuals. The health exam is the service that was
10 received and for which the payment was made.

11 The Company made an error in the service period it used to measure the payment
12 lag. As I indicate at the outset of the cash working capital section of this testimony, the
13 payment lag is supposed to measure from the mid-point of the period in which the service
14 was performed to the payment date for that service. The Company's calculation treats
15 the service lag as if the executive health exams were performed every day during 2007.
16 Clearly, this was not what happened because Equitable provided specific dates on which
17 the exams were done. As a result of this error, I have corrected the lag days for executive
18 health exams using the date on which the exam occurred as the service period. The
19 resulting amounts and dollar days have been reflected in the overall lag days for pension
20 and benefits presented on Schedule LKM-6, page 7.

21 **Q. WHAT IS THE NEXT CORRECTION YOU MADE TO THE LEAD-LAG**
22 **STUDY?**

23 A. The next correction I made to the Company's lead-lag study involves the payroll taxes
24 lag days. In the lead-lag study, Equitable explains that payroll taxes are paid on the same
25 date as the payroll. Accordingly, the Company indicates that the payroll taxes lag is the

1 same as the payroll lag. I do not disagree with the notion that the payroll taxes lag is the
2 same as the payroll lag. However, the calculation of the lag days applied to the Taxes
3 Other Than Income Expense category in the lead-lag study did not include the payroll
4 taxes even though the Taxes Other Than Income expenses, to which those lag days were
5 applied, includes the payroll taxes.

6 When the OCA sought an explanation of this discrepancy, the Company
7 responded that payroll taxes are included with payroll expenses since they are paid at the
8 same time. That response implies that, in the lead-lag study, the payroll expense amount
9 includes the payroll taxes, and that payroll taxes have been removed from Taxes Other
10 Than Income. However, the Company's statement is not accurate. When the O&M
11 Expense and Taxes Other Than Income amounts presented in the lead-lag study
12 (Company Exhibit VI, Item 18, Page 2) are compared with similar amounts presented in
13 the cost of service (Company Future Test Year Exhibit III-A-17, Sheets 4 and 6), it is
14 clear that payroll taxes are, in fact, included in Taxes Other Than Income and not Payroll
15 Expense in the lead-lag study. Therefore, I have corrected this error by recalculating the
16 Taxes Other than Income lag by including payroll taxes at a payment lag equal to the
17 payroll lag days. This calculation is presented on Schedule LKM-6, page 10.

18 **Q. ARE THERE ANY OTHER CORRECTIONS OR CHANGES THAT YOU**
19 **HAVE MADE TO THE LEAD-LAG STUDY?**

20 A. Yes. As I discuss later in this testimony, I have made several adjustments to O&M
21 expenses and taxes in the cost of service, which are additional components used by the
22 Company in the lead-lag study. Since I have concluded that the adjustments I have made
23 are necessary to establish reasonable rates, those adjustments must also be incorporated
24 into the lead-lag study. On Schedule LKM-6, page 1, I have incorporated those
25 adjustments into the lead-lag study.

1 **Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO CASH WORKING**
2 **CAPITAL.**

3 A. As a result of the corrections that I have discussed above , I am recommending an
4 adjustment to reduce cash working capital by \$5,785,973. This adjustment is presented
5 on Schedule LKM-6, page 1.
6

7 **Operating Revenues**

8 **Sales Revenues**

9 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO SALES REVENUES.**

10 A. I have made an adjustment to increase sales revenues by \$22,790,905. This adjustment is
11 the recommendation of OCA witness Glenn Watkins, and is supported in his direct
12 testimony.
13

14 **Expense Adjustments**

15 **Collection Costs**

16 **Q. WHY HAVE YOU REVERSED THE COMPANY'S CLAIM THAT**
17 **INCLUDES COLLECTION COSTS IN O&M EXPENSES?**

18 A. Equitable has made a pro forma adjustment to increase O&M expenses by \$612,202 to
19 reclassify collection costs that were recorded in accounts receivable to operating
20 expenses. Although the Company has proposed this adjustment, it admits that its normal
21 accounting practice is to include collection costs in accounts receivable and that the
22 adjustment it is proposing is not an adjustment to correct an error. Moreover, Equitable
23 states that an adjustment to reclassify collection costs has not actually been made on its
24 books.

1 Upon further inquiry, the Company indicated in response to OCA VIII-12 that
2 these were third party collection costs that had increased since the last rate case.
3 According to Equitable, these costs are not included in current base rates, so it recorded
4 them against the accounts receivable reserve, and is now including them in O&M
5 expenses in an attempt to begin recovering these costs. Equitable states that the actual
6 entry has not been made but that such an entry will be made pending the outcome of this
7 proceeding.

8 **Q. DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT?**

9 A. No. The Company's adjustment is inappropriate for three reasons. First, the Company
10 adjustment constitutes retroactive ratemaking. The Company's own words describe the
11 costs as costs incurred since the last rate case that were not included in current base rates.
12 By including those collection costs in this proceeding, the Company is attempting to
13 recover costs which were accumulated before the test year when the rates established
14 were deemed reasonable. Retroactive ratemaking is not allowed by this Commission.

15 Second, the Company's accounting for these collection costs is essentially an
16 unauthorized deferred accounting for these costs. In accounting for these costs, the
17 Company has accumulated costs in the accounts receivable reserve, which were not
18 included in the cost of service when current rates were established, and is now seeking to
19 pass through to customers in rates to be established from this proceeding. The deferral of
20 costs in a prior period and recovery in a subsequent period must be authorized by the
21 Commission. The Company has not received such authorization.

22 Finally, even though these costs were accumulated over time, Equitable is seeking
23 to recover the entire \$612,202 as if they are annually recurring collection costs, when it
24 does not incur such annually recurring costs. If these costs are included at this level,
25 O&M expenses will be overstated by \$612,202.

1 Based on the foregoing discussion, I am recommending the Company's
2 adjustment of \$612,202 be disallowed. As shown on Schedule LKM-8, I have removed
3 these costs from the cost of service. There is still an outstanding data request on this
4 issue. Upon receiving this response I will update this adjustment if necessary.

5
6 **Anode Expenses**

7 **Q. WHY HAVE YOU RECOMMENDED AN ADJUSTMENT TO REDUCE**
8 **EQUITABLE'S CLAIMED O&M EXPENSES FOR COSTS RELATED TO**
9 **ANODES?**

10 A. Equitable describes an anode as an electrode through which electric current flows into a
11 polarized electronic device to distribute cathodic protection to pipes. Historically, these
12 costs were expensed during the period they were incurred. During the historic test year,
13 the Company recorded \$1,269,658 in O&M expenses as costs related to the use of anodes
14 for cathodic protection. Beginning in 2008, the Company changed its accounting policy
15 after it was confirmed that cathodic protection extends the useful life of steel pipes. As a
16 result, the costs related to cathodic protection are now being capitalized. The Company's
17 adjustment removes \$1,000,000 from the cost of service in an attempt to recognize that
18 these costs would no longer be recorded as O&M expenses on an ongoing basis.
19 However, the removal of the \$1,000,000 does not include the entire amount incurred
20 during the test year for cathodic protection (\$1,269,658).

21 The Company's reason for removing only \$1,000,000 from the cost of service is
22 that it estimates that amount to be the level of costs related to anodes that will be
23 capitalized during the future test year. However, removing \$1,000,000 leaves \$269,658
24 in operating expenses related to cathodic protection in cost of service. Equitable,
25 however, claims these costs are representative of routine inspection of anodes and

1 corrosion. Yet, the Company has also included costs for inspection activities in its
2 maintenance expense adjustment. As a result, some of these costs are duplicative. The
3 OCA has sought additional information on this matter, and will update this adjustment if
4 necessary.

5 The \$269,658 adjustment that I am recommending is necessary to remove the
6 remaining expenses that are included in O&M expenses related to cathodic protection
7 because the Company stated they will no longer be recognized as O&M expenses on an
8 ongoing basis. On Schedule LKM-9, I present this adjustment, which decreases O&M
9 expenses by \$269,658. There is an outstanding data request on this issue. Upon
10 receiving the response, I will update this adjustment if necessary.

11 **Customer Experience Study**

12 **Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE CUSTOMER** 13 **EXPERIENCE STUDY COSTS?**

14 A. During 2007, the Company conducted an in-depth customer experience study. The
15 Company expects to use the study results as the baseline from which future customer
16 experience can be evaluated. The study was conducted after a number of significant
17 changes were made to the Company's operations. Specifically, Equitable had completed
18 the installation of a new customer information system, an Automated Meter Reading
19 system, a mobile dispatching/work order management system, and it expanded call center
20 service hours.

21 In the response to OCA I-26, Equitable acknowledges that customer experience
22 surveys are not performed annually and in fact could be performed with differing scopes.
23 Hence, I am recommending an adjustment that recognizes the infrequent nature of such
24 studies. Given the significant costs of \$795,858 that the Company claims for the study, I

1 am recommending an adjustment to normalize these costs over a 5-year period. The 5-
2 year period is consistent with the period I used for the normalization of regulatory
3 commission expenses and is consistent with Commission precedent for such expenses.
4 On Schedule LKM-10, I have reduced O&M expenses by \$636,686 to normalize
5 customer experience study costs.
6

7 **PA One Call Expense**

8 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S PA**
9 **ONE CALL EXPENSE.**

10 A. Equitable has included the cost of a recent contract with an outside contractor that
11 provides line location and other services. The costs included in the cost of service were
12 based upon a billing rate of \$17.50 per unit. In addition, Equitable claimed public
13 awareness and work management support costs in deriving the total annual cost of
14 \$572,183 for this contract.

15 I have reviewed the Company's contract with the vendor of these services in
16 conjunction with my evaluation of the costs included in the cost of service. My
17 adjustment corrects the billing rate per unit to be consistent with the contract with the
18 vendor and removes the public awareness and work management support costs because
19 they are not incremental costs.

20 With regard to the billing rate per unit, I have used the rate per unit that is stated
21 in the contract. According to the contract that rate will be fixed for three years.
22 Therefore, it is appropriate to use this rate. With regard to the public awareness and work
23 management support costs, the Company indicates that these costs were previously
24 incurred. Since the Company's claim is intended to include the costs of the new contract,
25 only new costs related to the contract should be reflected. Therefore, I have removed the

1 public awareness and work management support costs from the cost of service because
2 they are not incremental costs and are already included in the cost of service. I have
3 presented my adjustment, which reduces O&M expenses by \$83,197, on Schedule LKM-
4 11.

5
6 **Lobbying Expenses**

7 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO LOBBYING EXPENSES.**

8 A. The Company's cost of service includes a total of \$123,593 in lobbying expenses. Out of
9 the total amount, \$122,009 was charged to the Company through corporate service
10 charges from its affiliates and/or its parent company. The remaining \$1,584 is calculated
11 based upon two percent of Equitable's American Gas Association (AGA) dues.
12 According to Equitable's response to Standard Data Request, Item No. 33, two percent of
13 AGA's operating budget is attributable to lobbying activities. Therefore, I have
14 attributed two percent of the Company's AGA dues as supporting lobbying activities.

15 **Q. WHY HAVE YOU REMOVED LOBBYING EXPENSES?**

16 A. For ratemaking, a utility's costs of service should include only those costs that are
17 necessary for the provision of utility service. Under traditional ratemaking principles,
18 lobbying is not considered an activity necessary for the provision of utility service.
19 Consequently, I have removed those expenses from the cost of service. This adjustment
20 is presented on Schedule LKM-12, resulting in a \$123,593 decrease in O&M expenses.

21
22 **Payroll and Benefits Expenses**

23 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PAYROLL EXPENSES.**

24 A. The Company's payroll claim is based upon adjusting the historic test year payroll
25 expense to an ongoing level based upon changes that were to occur by the end of the

1 future test year. The historical test year was first adjusted to include open positions that
2 the Company expected to be filled and to remove the costs associated with positions that
3 were transferred to other affiliates. Next, the Company included a claim for a three
4 percent merit rate increase, promotions and other allocated labor costs, and the costs of
5 newly hired employees. These series of adjustments reflected the payroll expense at the
6 ongoing level at the end of the future test year. Further, Equitable added the costs of
7 fringe benefits. The fringe benefits costs were derived by applying the fringe benefits
8 rate to the future test year payroll costs. The fringe benefits rate was calculated based
9 upon the ratio of the fringe benefits paid during the historical test year to the payroll paid
10 during the same period.

11 The adjustment I made removes the costs associated with positions that are not
12 currently filled and a position that was included twice. With regard to the positions that
13 were not filled, the Company's response to OCA I-11 identifies each of the positions that
14 were included in its adjustment to include the costs of newly hired employees. There
15 were four positions that were identified as not being filled. I have removed the costs
16 associated with those four positions in order to reflect the most recent actual number of
17 employees. The use of the actual number of employees is reasonable because these
18 positions are newly created positions based upon an anticipated expansion.
19 Consequently, there is some uncertainty regarding if, or when, these positions will be
20 filled. If these costs are included in rates, and the positions are not filled, the Company
21 will over-recover these costs. Moreover, there is always a level of unfilled positions due
22 to employee attrition. Removing these costs is necessary to eliminate payroll costs that
23 will not be incurred.

24 With regard to the position that was included twice, it appears that both the costs
25 of the former employee and the replacement employee were inadvertently included in the

1 payroll. The former employee left the Company on December 31, 2007, and was
2 replaced by an employee that was hired in January 2008. The cost of the former
3 employee remained in the Company's payroll claim, and a merit increase was even added
4 on the historical test year amount. The Company also included the annual cost of the
5 person hired to fill the former employee's position in its adjustment to reflect newly hired
6 employees. As a result, the position is included twice in the payroll claim and must be
7 removed.

8 In addition to the removal of the payroll costs, I have removed the fringe benefits
9 associated with each position. This is necessary since fringe benefits were included for
10 each position based upon a percentage of payroll costs. On Schedule LKM-13, I present
11 this adjustment resulting in a \$342,428 decrease in O&M expenses.

12
13 **Pension and Postretirement Benefits Other Than Pensions**

14 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PENSIONS AND**
15 **POSTRETIREMENT BENEFITS OTHER THAN PENSION.**

16 The Company's future test year claims for pension and postretirement benefits other than
17 pensions were the historical test year amounts for these expenses. The Company has
18 provided the 2008 actuarial study for these costs. The adjustment I am recommending is
19 necessary to include the 2008 actuarial amounts rather than the historical test year
20 amounts. The use of the 2008 amounts is more appropriate because they reflect the most
21 recent costs. On Schedule LKM-14, I present this adjustment that reduces O&M
22 expenses by \$463,473.

1 **Regulatory Commission Expenses**

2 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REGULATORY**
3 **COMMISSION EXPENSES.**

4 A. Equitable has increased the claimed cost of service to normalize the cost of this rate
5 proceeding over a three-year period, and to normalize the costs of the Service Life Study
6 and the upcoming management audit over a five-year period. The adjustment I am
7 recommending changes the normalization period and removes costs that have not been
8 incurred.

9 First, I have removed the upcoming management audit costs. These costs were
10 removed because the audit has not yet begun and the costs the Company is seeking to
11 recover have not been incurred. As a result these costs are not eligible for recovery in
12 current rates.

13 The second change I have made is to normalize the cost of this proceeding over a
14 five-year period. The three-year period proposed by the Company should not be used
15 because it normalizes rate case expense over a period that is much shorter than the period
16 between this case and the last rate case, which was filed on February 28, 1997. The use
17 of the five-year period is also consistent with the period the Company proposed to
18 normalize the management audit and the Service Life Study.

19 Finally, in the Company's response to OCA IV-8, Equitable identified certain
20 costs that were related to its West Virginia jurisdiction. The Company admits that these
21 costs should not be included in Pennsylvania jurisdictional rates. Therefore, I have
22 removed them from regulatory commission expenses to be recovered in this proceeding.
23 The adjustment I am recommending is summarized on Schedule LKM-15 and results in a
24 \$298,781 decrease to O&M expenses.
25

1 **Cost of Fuel**

2 **Q. WHAT ADJUSTMENT HAVE YOU MADE TO COST OF FUEL?**

3 A. Equitable made an adjustment to include the increased cost of gasoline and diesel fuel
4 used by its vehicles. The Company's adjustment was based upon the escalation of the
5 historical test year costs by approximately 25 percent to reflect recent spikes in gasoline
6 and diesel fuel prices. In response to an OCA interrogatory, the Company indicated that
7 it had installed GPS devices in all its vehicles, which have resulted in a 7.5 percent
8 decrease in the average miles driven. In addition, vehicles are now required to be turned
9 off at service stops. Accordingly, the Company's data for 2008 shows a decrease in the
10 number of gallons of fuel consumed by the Company. However, this reduction was not
11 reflected in Equitable's cost of service claim for fuel costs.

12 The adjustment I am recommending is necessary to reflect the net decrease in the
13 cost of fuel experienced by the Company that has resulted from its changes in policy that
14 require turning off vehicles and the use of GPS devices. Essentially, the fuel cost borne
15 by the Company has two components -- a price component and a usage component. The
16 Company's adjustment captures the price component, but not the usage component. To
17 properly reflect the fuel costs, it is necessary to also reflect the changes in the usage. The
18 adjustment I have made combines both the price and usage changes and results in a net
19 increase in fuel costs. I derived my adjustment by annualizing the Company's actual fuel
20 usage for the first eight months of 2008 and the Company's 2008 price per gallons rates
21 that it used in its adjustment. The result is decrease of \$69,623. This adjustment is
22 presented on Schedule LKM-16.

1 **Injuries and Damages**

2 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO INJURIES AND**
3 **DAMAGES EXPENSE.**

4 A. Under current accounting practices, a company must record, as an expense, potential
5 claims for which it may be liable during the period in which the Company determines
6 liability is likely to be incurred. Each year the Equitable accrues these costs as expenses
7 to injuries and damages expenses and records the corresponding liability amount in a
8 reserve account. Later during the year, the reserve account is analyzed to determine
9 whether the amount recorded is adequate to meet potential claims. An adjustment (the
10 adjusting entry) is made (either an increase or decrease) to bring the value of the reserve
11 more in line with the Company's actuarial expectations.

12 During the historical test year, as a result of the reserve analysis, Equitable made
13 an adjusting entry to reduce the reserve account by \$3,145,292 because it was found to be
14 too high. The adjusting entry made by the Company to reduce the reserve also reduced
15 the injuries and damages expense by \$3,145,292. In the cost of service in the rate case,
16 the Company made an adjustment to normalize the injuries and damages expense. In that
17 adjustment, Equitable essentially reverses the \$3,145,292 adjusting entry that reduced
18 injuries and damages in its historical test year operating expenses. With this adjustment
19 the Company considers the injuries and damages expense to be normalized.

20 I disagree with the Company's adjustment because Equitable treats the adjusting
21 entry as if it is an unusual or one-time occurrence. It is not. An adjusting entry is made
22 virtually every year to recognize changes in the actuarial estimates that are used to record
23 the monthly expense. Through quarterly reviews the adequacy of the reserve is assessed,
24 as explained in the Company's response to OTS-RE-87-D. Because of this process of
25 accruing the expense and later "correcting" through the adjusting entries, it is necessary

1 to combine the expense accrual and the adjusting entry to derive the annual expense. The
2 adjustment proposed by the Company results in an overstatement of the injuries and
3 damages expense because it removes the adjusting entry that is needed to properly reflect
4 the injuries and damages expense.

5 The adjustment I have made normalizes the injuries and damages expense using
6 the actual claims paid by the Company. In addition, I used a three-year average of actual
7 claims paid as the normalized expense amount. It is more appropriate to use my
8 approach because the actual claims are the actual cash payments made by the Company
9 to settle claims. It is preferable because the accrued expense, which is reflected on the
10 Company's books, is always an estimate. That is why adjusting entries are routine.

11 In addition, I have used the three-year average because claims have a tendency to
12 fluctuate from year to year. The three-year average smooths out the fluctuations and
13 normalizes the level of expenses.

14 **Q. WHAT IS THE RESULT OF YOUR ADJUSTMENT TO INJURIES AND**
15 **DAMAGES?**

16 A. The adjustment I am recommending is a reduction in O&M expense of \$2,755,953. This
17 adjustment is presented on Schedule LKM-17.

18
19 **Right-of-Way Mowing**

20 **Q. WHY DID YOU ADJUST THE LEVEL OF EXPENSE RELATED TO**
21 **RIGHT-OF-WAY MOWING?**

22 A. Equitable increased O&M expense by \$384,431 because it wanted to normalize its right-
23 of-way mowing expense. According to the Company, the basis of the adjustment was to
24 include an amount that is associated with the mowing of its gathering and transmission
25 facilities right-of-way. I have reviewed the Company's most recent three-year average of

1 rights-of-way mowing costs and found that the Company has never reported right-of-way
2 mowing as high as \$384,000. Hence adding \$384,431 to the amount recorded on its
3 books of \$55,479 in no way reflects a normalized level of these expenses. Moreover, the
4 Company has made an adjustment in the future test year to include an additional
5 \$100,000 for right-of-way mowing. The combined adjustment is excessive when
6 compared to the Company's recent history of these expenses. Therefore on Schedule
7 LKM-18, I have reduced O&M expenses by \$384,431.

8
9 **DOT Compliance Costs**

10 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REVERSE THE**
11 **COMPANY'S DEPARTMENT OF TRANSPORTATION (DOT)**
12 **COMPLIANCE COSTS CLAIM?**

13 A. The cost of service presented by Equitable includes an adjustment to increase O&M
14 expenses by \$133,524 for costs related to DOT compliance. Upon further investigation,
15 it was determined that these costs are those incurred to cathodically protect pipes.

16 Elsewhere in its filing, Equitable has indicated that it has changed its accounting
17 policy and now capitalizes cathodic protection costs. To be consistent with the
18 Company's accounting policies, these costs should be removed from O&M expenses.
19 Therefore, on Schedule LKM-19 I have removed the \$133,524 from the cost of service.

20 **Q. ON WHAT BASIS DO YOU CONCLUDE THAT THESE COSTS ARE**
21 **CAPITAL COSTS?**

22 A. In the Company's response to OCA VIII-6, Equitable explains that these costs are
23 associated with remediation of cathodically protected pipelines. Equitable states that
24 "[r]emedial work includes rehabilitation of existing cathodic protection systems, clearing
25 metallic shorts to foreign utility, restoring coating or repairing or renewing insulation

1 joints.” In the response to OCA VIII-8, Equitable states that “[r]ehabilitation of existing
2 cathodic protection system involves replacement of depleted anodes.” According to the
3 Company’s new accounting policy, replacement of anodes is to be capitalized. In
4 Equitable’s response to OCA I-19, the Company states that “all costs related to planned
5 replacement of anodes on a large scale across a significant pipeline segment shall be
6 capitalized.” Therefore, it appears that the costs associated with this 62.7-mile project
7 should be capitalized under the Company’s accounting policy.
8

9 **Universal Service Expenses**

10 **Q. WHY HAVE YOU ADJUSTED UNIVERSAL SERVICE EXPENSE?**

11 A. OCA witness Roger Colton has addressed the Company’s universal service program in
12 his direct testimony, and he determined that the Company overstated its projected
13 universal service costs by \$10,380,693. Based upon his recommendation, I have made an
14 adjustment that can be found on Schedule LKM-20 to reduce O&M expenses by the
15 overstated amount.
16

17 **Interest Synchronization**

18 **Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION**
19 **ADJUSTMENT.**

20 A. To determine the tax-deductible interest for ratemaking, I have multiplied the adjusted
21 rate base by the weighted cost of debt included in the capital structure. This procedure
22 synchronizes the interest deduction for tax purposes with the interest component of the
23 return on rate base to be recovered from ratepayers. As shown in Schedule LKM-21, this
24 adjustment increases the interest deduction by \$758,894 compared to the interest

1 deduction recognized by Equitable in its filing. This decreases state and federal income
2 taxes by \$75,814 and \$239,078 respectively.

3 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

4 A. Yes. However, I reserve the right to supplement this testimony to reflect any adjustments
5 deemed necessary once outstanding discovery responses are received from Equitable.

6
7
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

EXHIBITS TO THE
DIRECT TESTIMONY OF
LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

OCTOBER 8, 2008

EXETER

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

EQUITABLE GAS COMPANY

Summary of Operating Income
For the Test Year Ended December 31, 2008

	PAPUC Jurisdictional Amount per Co.	OCA Cost of Service Adjustments	Amount After Adjustments	OCA Recommended Change In Revenue	After Proposed Revenue Change
<u>Operating Revenues</u>					
Total Operating Revenues	\$ 516,617,530	\$ 22,790,905	\$ 539,408,435	\$ (4,610,365)	\$ 534,798,070
<u>Operating Expenses</u>					
Purchased Gas Costs	\$ 359,315,773	\$ -	\$ 359,315,773	\$ -	\$ 359,315,773
Non-purchased Gas Costs	105,108,151	(16,554,242)	88,553,909	(97,563)	88,456,346
Depreciation & Amortization Expenses	23,471,055	-	23,471,055	-	23,471,055
Taxes Other Than Income	2,185,866	-	2,185,866	(12,706)	2,173,160
Current Federal Income Tax	(3,182,873)	12,156,022	8,973,149	(449,560)	8,523,589
Current State Income Tax	(1,009,313)	3,854,766	2,845,453	(1,417,688)	1,427,765
Deferred Federal Income Taxes	8,545,747	-	8,545,747	-	8,545,747
Investment Tax Credit	(5,529)	-	(5,529)	-	(5,529)
Total Operating Expenses	\$ 494,428,877	\$ (543,454)	\$ 493,885,423	\$ (1,977,517)	\$ 491,907,906
Net Operating Income	\$ 22,188,653	\$ 23,334,359	\$ 45,523,012	\$ (2,632,848)	\$ 42,890,164
Rate Base	\$ 583,252,590		\$ 575,704,990		\$ 575,704,990
Return On Rate Base	3.80%		7.91%		7.45%

EQUITABLE GAS COMPANY

Summary of Revenue Increase at OCA Rate of Return
For the Test Year Ended December 31, 2008

		<u>Amount</u>	<u>Source</u>
Adjusted Rate Base		\$ 575,704,990	Schedule LKM-2, Page 2
Required Rate of Return		<u>7.450%</u>	
Net Operating Income Required		\$ 42,890,022	
Net Operating Income at Present Rates		<u>45,523,012</u>	Schedule LKM-1, Page 1
Income Deficiency/(Surplus)		\$ (2,632,990)	
Revenue Multiplier		<u>1.751</u>	
Required Change in Company Revenue		<u>\$ (4,610,365)</u>	
Proposed Revenue Change		\$ (4,610,365)	
Uncollectibles	1.920%	(88,519)	
PUC, OCA, OSBA Assessments	0.281%	(12,706)	
LIURP	0.200%	<u>(9,044)</u>	
Subtotal		\$ (4,500,096)	
State Income Tax	9.99%	<u>(449,560)</u>	
Subtotal		\$ (4,050,536)	
Federal Income Tax	35.00%	<u>(1,417,688)</u>	
Net Income Increase Required		<u>\$ (2,632,848)</u>	

EQUITABLE GAS COMPANY

Summary of Rate Base
For the Test Year Ended December 31, 2008

	PAPUC Jurisdictional Amount per Co.	OCA Rate Base Adjustments	Amount After Adjustments
Total Plant in Service	\$ 897,954,727	\$ (1,761,627)	\$ 896,193,100
Accumulated Depreciation	(289,353,072)	-	(289,353,072)
Net Plant in Service	\$ 608,601,655	\$ (1,761,627)	\$ 606,840,028
<u>Additions:</u>			
Materials & Supplies	\$ 887,426	\$ -	\$ 887,426
Current Gas Storage	75,175,769	-	75,175,769
Cash Working Capital	11,335,335	(5,785,973)	5,549,362
Prepayments	234,270	-	234,270
Total Additions	\$ 87,632,800	\$ (5,785,973)	\$ 81,846,827
<u>Deductions:</u>			
Accumulated Deferred Income Taxes	\$(104,709,261)	\$ -	\$(104,709,261)
Income Tax Credits	(4,902,910)	-	(4,902,910)
Customer Advances	-	-	-
Customer Deposits	(3,369,694)	-	(3,369,694)
Total Deductions	\$(112,981,865)	\$ -	\$(112,981,865)
Total Rate Base	<u>\$ 583,252,590</u>	<u>\$ (7,547,600)</u>	<u>\$ 575,704,990</u>

EQUITABLE GAS COMPANY

Summary of Rate Base Adjustments
For the Test Year Ended December 31, 2008

	<u>Source</u>	<u>PAPUC Jurisdictional Amount per Co.</u>
Rate Base per Company Filing	Schedule LKM-2, Page 1	<u>\$ 583,252,590</u>
<u>OCA Adjustments:</u>		
Plant in Service		\$ (1,761,627)
Cash Working Capital		<u>(5,785,973)</u>
Total Ratemaking Adjustments		<u>\$ (7,547,600)</u>
Adjusted Rate Base per OCA		<u><u>\$ 575,704,990</u></u>

EQUITABLE GAS COMPANYSummary of Adjustments to Net Income
For the Test Year Ended December 31, 2008

	<u>Total Company Amount</u>
Net Income per Company	<u>\$ 22,188,653</u>
<u>OCA Adjustments:</u>	
Annualize Operating Revenues	\$ 13,334,161
Reverse Company's Collection Cost Adjustment	358,178
Remove Excess Anode Expenses	157,767
Normalize Customer Experience Study Costs	372,503
Annualize PA One Call Expense	48,676
Remove Lobbying Expenses	72,310
Annualize Payroll Expenses	200,342
Reflect Ongoing Level of Pension & OPEB Costs	271,162
Normalize Regulatory Commission Expenses	174,806
Annualize the Increase in Cost of Fuel	40,734
Normalize Injuries & Damages Expense	1,612,411
Normalize Right of Way Mowing Expense	224,917
Reverse Cathodic Protection Costs	78,120
Universal Service Costs per OCA	6,073,380
Interest Synchronization	<u>314,892</u>
Total Ratemaking Adjustments	<u>\$ 23,334,359</u>
Total Adjusted Net Income per OCA	<u><u>\$ 45,523,012</u></u>

EQUITABLE GAS COMPANY

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2008

	Operating Revenues	O&M Expenses	Depreciation & Amortization Expenses	Taxes Other Than Income	Current State Income Tax	Current Federal Income Taxes	Deferred Income Taxes	Investment Tax Credit	Net Operating Income
PA Jurisdictional Amount per Company	\$ 516,617,530	\$464,423,924	\$ 23,471,055	\$ 2,185,866	\$ (1,009,313)	\$ (3,182,873)	\$ 8,545,747	\$ (5,529)	\$ 22,188,653
<u>OCA Adjustments:</u>									
Annualize Operating Revenues	\$ 22,790,905	\$ -	\$ -	\$ -	\$ 2,276,811	\$ 7,179,933	\$ -	\$ -	\$ 13,334,161
Reverse Company's Collection Cost Adjustment	-	(612,202)	-	-	61,159	192,865	-	-	358,178
Remove Excess Abode Expenses	-	(269,658)	-	-	26,939	84,952	-	-	157,767
Normalize Customer Experience Study Costs	-	(636,688)	-	-	63,605	200,578	-	-	372,503
Annualize PA One Call Expense	-	(83,197)	-	-	8,311	26,210	-	-	48,676
Remove Lobbying Expenses	-	(123,593)	-	-	12,347	38,936	-	-	72,310
Annualize Payroll Expenses	-	(342,428)	-	-	34,209	107,877	-	-	200,342
Reflect Ongoing Level of Pension & OPEB Costs	-	(463,473)	-	-	46,301	146,010	-	-	271,162
Normalize Regulatory Commission Expenses	-	(298,781)	-	-	29,848	94,127	-	-	174,806
Annualize the Increase in Cost of Fuel	-	(69,623)	-	-	6,955	21,934	-	-	40,734
Normalize Injuries & Damages Expense	-	(2,755,953)	-	-	275,320	868,222	-	-	1,612,411
Normalize Right of Way Mowing Expense	-	(384,431)	-	-	38,405	121,109	-	-	224,917
Reverse Cathodic Protection Costs	-	(133,524)	-	-	13,339	42,065	-	-	78,120
Universal Service Costs per OCA	-	(10,380,693)	-	-	1,037,031	3,270,282	-	-	6,073,380
Interest Synchronization	-	-	-	-	(75,814)	(239,078)	-	-	314,892
Total Rate-making Adjustments	\$ 22,790,905	\$ (16,554,242)	\$ -	\$ -	\$ 3,854,766	\$ 12,156,022	\$ -	\$ -	\$ 23,334,359
Total Adjusted Income	\$ 539,408,435	\$447,869,682	\$ 23,471,055	\$ 2,185,866	\$ 2,845,453	\$ 8,973,149	\$ 8,545,747	\$ (5,529)	\$ 45,523,012

EQUITABLE GAS COMPANY

Reconciliation of Current State and Federal Income Taxes
For the Test Year Ended December 31, 2008

	Test Year Per Company	Ratemaking Adjustments	Test Year at Present Rates	Increase at OCA Rate of Return	After Proposed Revenue Change
CALCULATION OF COMBINED CURRENT INCOME TAX					
Net Operating Income Before Income Taxes	\$ 26,536,685	\$ 39,345,147	\$ 65,881,832	\$ (4,500,096)	\$ 61,381,736
<u>Adjustments for Income Taxes</u>					
Interest Expense	(16,972,820)	(758,894)	(17,731,714)	-	(17,731,714)
Book Depreciation Expense	23,471,055	-	23,471,055	-	23,471,055
Tax Depreciation Expense	(43,138,325)	-	(43,138,325)	-	(43,138,325)
State Taxable Income	\$ (10,103,405)	\$ 38,586,253	\$ (19,667,270)	\$ (4,500,096)	\$ (19,667,270)
State Income Tax	9.99% \$ (1,009,330)	\$ 3,854,767	\$ (1,964,760)	\$ (449,560)	\$ (1,964,760)
Federal Taxable Income Before State Income Tax	\$ (10,103,405)	\$ 38,586,253	\$ 28,482,848	\$ (4,500,096)	\$ 23,982,752
State Income Tax	(1,009,330)	3,854,767	2,845,437	(449,560)	2,395,877
Federal Taxable Income	\$ (9,094,075)	\$ 34,731,486	\$ 25,637,411	\$ (4,050,536)	\$ 21,586,875
Federal Income Tax	35.00% (3,182,926)	12,156,020	8,973,094	(1,417,688)	7,555,406
Federal Tax Credits	(5,529)	-	(5,529)	-	(5,529)
Net Federal Income Tax	\$ (3,188,455)	\$ 12,156,020	\$ 8,967,565	\$ (1,417,688)	\$ 7,549,877
Net Combined Current Income Tax	\$ (4,197,785)	\$ 16,010,787	\$ 11,813,002	\$ (1,867,247)	\$ 9,945,755
Total Combined Current Income Taxes (Schedule LKM-1, Page 1)	(4,197,715)	16,010,788	11,813,073	(1,867,248)	9,945,825
Unreconciled/Rounding	\$ (70)	\$ (1)	\$ (71)	\$ 1	\$ (70)

EQUITABLE GAS COMPANY

Adjustment to Plant in Service
For the Test Year Ended December 31, 2008

	<u>Amount</u>
<u>Post-Test Year plant in Service</u>	
Purchase New Meters and Regulators	\$ 636,394 1/
Tools and Equipment	242,451 1/
PC and Laptop Replacement	141,000 1/
Automotive Replacements	<u>741,782 1/</u>
Total Adjustment to Plant in Service	<u><u>\$ 1,761,627</u></u>

Notes:

1/ Response to OCA IV-26.

EQUITABLE GAS COMPANY

Adjustment to Allowance for Cash Working Capital
For the Test Year Ended December 31, 2008

	Pro Forma Expenses	1/	OCA Adjustments	Adjusted Pro Forma Expenses	Daily Requirement	Revenue Lag Days	1/	Expense Lag days	1/	Net Lag Days	Working Capital Requirement
<u>Operating Expense</u>											
Purchased Gas	\$ 359,315,773		\$ -	\$ 359,315,773	\$ 984,427	49.29		45.91		3.38	\$ 3,327,363
Payroll	24,095,087		(263,467)	23,831,620	65,292	49.29		45.91	2/	3.38	220,701
Employee Benefits	7,069,423		(522,589)	6,546,834	17,937	49.29		17.20		32.09	575,535
Corporate Services	15,990,000		(122,009)	15,867,991	43,474	49.29		49.29		-	-
Injuries & Damages	4,803,788		(2,755,953)	2,047,835	5,611	49.29		(164.74)		214.03	1,200,922
Uncollectibles	25,049,825		(88,519)	24,961,306	68,387	49.29		49.29		-	-
Other O&M Expenses	28,100,026		(12,879,423)	15,220,603	41,700	49.29		36.84		12.45	519,319
	<u>\$ 464,423,922</u>			<u>\$ 447,791,982</u>							
Depreciation & Amortization	23,471,055		-	23,471,055	-						-
Taxes Other Than Income	2,185,866		(32,571)	2,153,295	5,899	49.29		(2.71)	3/	52.00	306,777
<u>Income Taxes</u>											
Current Federal	(3,182,873)		11,706,462	8,523,589	23,352	49.29		36.50		12.79	298,676
Current State	(1,009,313)		2,437,078	1,427,765	3,912	49.29		51.58		(2.29)	(8,958)
Deferred Federal & State	8,545,747		-	8,545,747							
Investment Tax Credit	(5,529)		-	(5,529)	-						-
Interest on Debt	16,972,650		759,064	17,731,714	48,580	49.29		72.58		(23.29)	(1,131,429)
Sales and Use Taxes	6,287,006		-	6,287,006	17,225	49.29		35.33		13.96	240,456
Cash Working Capital per OCA											\$ 5,549,362
Cash Working Capital per Company											<u>11,335,335</u>
Adjustment to Cash Working Capital											<u>\$ (5,785,973)</u>

Notes:

- 1/ Exhibit VI, Item 18, page 2.
2/ Schedule LKM-5, page 3.
3/ Schedule LKM-5, page 10.

EQUITABLE GAS COMPANY

Calculation of Non-Union Payroll Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	1/ Lag Days	1/ Amount	1/ Dollar Days
12/18/06	12/31/06	12/24/06	01/10/07	16.50	\$ 663,113	\$ 10,941,365
01/01/07	01/14/07	01/07/07	01/24/07	16.50	663,604	10,949,466
01/01/06	12/31/06 2/	07/02/06	02/06/07	219.00	3,650,116 2/	799,375,404
01/15/07	01/28/07	01/21/07	02/07/07	16.50	665,254	10,976,691
01/29/07	02/11/07	02/04/07	02/21/07	16.50	656,666	10,834,989
02/12/07	02/25/07	02/18/07	03/07/07	16.50	650,454	10,732,491
02/26/07	03/11/07	03/04/07	03/21/07	16.50	682,704	11,264,616
03/12/07	03/25/07	03/18/07	04/04/07	16.50	658,826	10,870,629
03/26/07	04/08/07	04/01/07	04/18/07	16.50	657,239	10,844,444
04/09/07	04/22/07	04/15/07	05/02/07	16.50	663,850	10,953,525
04/23/07	05/06/07	04/29/07	05/16/07	16.50	669,857	11,052,641
05/07/07	05/20/07	05/13/07	05/30/07	16.50	664,132	10,958,178
05/21/07	06/03/07	05/27/07	06/13/07	16.50	666,519	10,997,564
06/04/07	06/17/07	06/10/07	06/27/07	16.50	663,067	10,940,606
06/18/07	07/01/07	06/24/07	07/11/07	16.50	664,892	10,970,718
07/02/07	07/15/07	07/08/07	07/25/07	16.50	662,533	10,931,795
07/16/07	07/29/07	07/22/07	08/08/07	16.50	649,673	10,719,605
07/30/07	08/12/07	08/05/07	08/22/07	16.50	648,531	10,700,762
08/13/07	08/26/07	08/19/07	09/05/07	16.50	635,798	10,490,667
08/27/07	09/09/07	09/02/07	09/19/07	16.50	640,692	10,571,418
09/10/07	09/23/07	09/16/07	10/03/07	16.50	591,651	9,762,242
09/24/07	10/07/07	09/30/07	10/17/07	16.50	593,444	9,791,826
10/08/07	10/21/07	10/14/07	10/31/07	16.50	596,533	9,842,795
10/22/07	11/04/07	10/28/07	11/14/07	16.50	598,294	9,871,851
11/05/07	11/18/07	11/11/07	11/28/07	16.50	590,987	9,751,286
11/19/07	12/02/07	11/25/07	12/12/07	16.50	629,265	10,382,873
12/03/07	12/16/07	12/09/07	12/26/07	16.50	589,239	9,722,444
				<u>52.79</u>	<u>\$ 20,366,933</u>	<u>\$ 1,075,202,885</u>

Notes:

1/ Exhibit VI, Item 18, page 11.

2/ Company response to OTS-RE-18-D.

EQUITABLE GAS COMPANY

Calculation of Union Payroll Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	1/ Lag Days	1/ Amount	1/ Dollar Days
12/18/06	12/31/06	12/24/06	01/12/07	18.50	\$ 393,762	\$ 7,284,597
01/01/07	01/14/07	01/07/07	01/26/07	18.50	386,120	7,143,220
01/01/06	12/31/06 2/	07/02/06	02/06/07	219.00	656,326	143,735,394
01/15/07	01/28/07	01/21/07	02/09/07	18.50	369,857	6,842,355
01/29/07	02/11/07	02/04/07	02/23/07	18.50	374,081	6,920,499
02/12/07	02/25/07	02/18/07	03/09/07	18.50	387,408	7,167,048
02/26/07	03/11/07	03/04/07	03/23/07	18.50	373,400	6,907,900
03/12/07	03/25/07	03/18/07	04/04/07	16.50	330,927	5,460,296
03/26/07	04/08/07	04/01/07	04/20/07	18.50	351,323	6,499,476
04/09/07	04/22/07	04/15/07	05/04/07	18.50	347,062	6,420,647
04/23/07	05/06/07	04/29/07	05/18/07	18.50	334,124	6,181,294
05/07/07	05/20/07	05/13/07	06/01/07	18.50	336,230	6,220,255
05/21/07	06/03/07	05/27/07	06/15/07	18.50	353,260	6,535,310
06/04/07	06/17/07	06/10/07	06/29/07	18.50	337,679	6,247,062
06/18/07	07/01/07	06/24/07	07/13/07	18.50	341,521	6,318,139
07/02/07	07/15/07	07/08/07	07/27/07	18.50	345,752	6,396,412
07/16/07	07/29/07	07/22/07	08/10/07	18.50	333,438	6,168,603
07/30/07	08/12/07	08/05/07	08/24/07	18.50	347,811	6,434,504
08/13/07	08/26/07	08/19/07	09/07/07	18.50	337,253	6,239,181
08/27/07	09/09/07	09/02/07	09/21/07	18.50	335,121	6,199,739
09/10/07	09/23/07	09/16/07	10/05/07	18.50	331,445	6,131,733
09/24/07	10/07/07	09/30/07	10/19/07	18.50	352,580	6,522,730
10/08/07	10/21/07	10/14/07	11/02/07	18.50	355,828	6,582,818
10/22/07	11/04/07	10/28/07	11/16/07	18.50	355,294	6,572,939
11/05/07	11/18/07	11/11/07	11/30/07	18.50	375,779	6,951,912
11/19/07	12/02/07	11/25/07	12/14/07	18.50	395,601	7,318,619
12/03/07	12/16/07	12/09/07	12/28/07	18.50	351,392	6,500,752
				<u>31.74</u>	<u>\$ 9,890,374</u>	<u>\$ 313,903,428</u>
Combined Payroll Amounts				<u>45.91</u>	<u>\$ 30,257,307</u>	<u>\$ 1,389,106,313</u>

Notes:

1/ Exhibit VI, Item 18, page 12.

EQUITABLE GAS COMPANY

Calculation of Corporate Services Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	Lag Days	2/ Amount	Dollar Days
01/01/07	01/31/07	01/16/07	n/a	49.29	\$ 1,311,496	\$ 64,643,638
02/01/07	02/28/07	02/14/07	n/a	49.29	1,354,246	66,750,785
03/01/07	03/31/07	03/16/07	n/a	49.29	1,354,246	66,750,785
04/01/07	04/30/07	04/15/07	n/a	49.29	1,354,246	66,750,785
05/01/07	05/31/07	05/16/07	n/a	49.29	1,354,246	66,750,785
06/01/07	06/30/07	06/15/07	n/a	49.29	1,267,733	62,486,560
07/01/07	07/31/07	07/16/07	n/a	49.29	1,354,246	66,750,785
08/01/07	08/31/07	08/16/07	n/a	49.29	1,354,246	66,750,785
09/01/07	09/30/07	09/15/07	n/a	49.29	1,331,410	65,625,199
10/01/07	10/31/07	10/16/07	n/a	49.29	1,354,246	66,750,785
11/01/07	11/30/07	11/15/07	n/a	49.29	1,354,246	66,750,785
12/01/07	12/31/07	12/16/07	n/a	49.29	1,449,883	71,464,733
				<u>49.29</u>	<u>\$ 16,194,490</u>	<u>\$ 798,226,412</u>

Notes:

1/ Exhibit VI, Item 18, page 13.

2/ Revenue Lag presented on Exhibit VI, Item 18, page 2.

EQUITABLE GAS COMPANY

Calculation of Other O&M-Goods & Services Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u>	<u>Amount</u> 1/	<u>Dollar Days</u> 1/
Other O&M Totals		\$ 3,568,382	\$ 100,655,431
Other Goods & Services Totals		11,640,164	399,128,278
OSS - NCO Totals		2,794,637	151,981,995
OSS - Trafford Totals		1,741,825	79,604,796
OSS - HEATH Consultants Totals		1,192,201	44,544,821
C. Leon Sherman & Associates		498,255	20,827,565
Pittsburgh Mailing & ADS		<u>848,033</u>	<u>24,098,883</u>
Other O&M Totals		<u>\$ 22,283,497</u>	<u>\$ 820,841,769</u>
Other O&M Lag Days	<u>36.84</u>		

Notes:

1/ Exhibit VI, Item 18, pages 14 - 18.

2/ Schedule LKM-6, Page 6.

EQUITABLE GAS COMPANY

Calculation of Other O&M-C. Leon Sherman Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/	Payroll Period End	1/	Mid Point of Service Period	1/	Payment Date	1/	Lag Days	1/	Amount	1/	Dollar Days
12/01/06		12/31/06		12/16/06		01/30/07		45.00		\$ 87,651		\$ 3,944,295
01/01/07		01/31/07		01/16/07		03/01/07		44.00		76,761		3,377,484
02/01/07		02/28/07		02/14/07		03/20/07		33.50		57,826		1,937,171
04/01/07		04/30/07		04/15/07		05/22/07		36.50		155,913		5,690,825
05/01/07		05/31/07		05/16/07		06/28/07		43.00		15,191		653,213
06/01/07		06/30/07		06/15/07		07/24/07 2/		38.50		7,479		287,942
07/01/07		07/31/07		07/16/07		08/28/07		43.00		24,015		1,032,645
09/01/07		09/30/07		09/15/07		10/04/07		18.50		9,285		171,773
09/01/07		09/30/07		09/15/07		11/13/07		58.50		24,893		1,456,241
10/01/07		10/31/07		10/16/07		12/13/07		58.00		39,241		2,275,978
								<u>41.80</u>		<u>\$ 498,255</u>		<u>\$ 20,827,565</u>

Notes:

1/ Exhibit VI, Item 18, pages 15 - 18.

2/ Response to OTS-RE-23-D.

EQUITABLE GAS COMPANY

Calculation of Pensions & Benefits Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u> 1/	<u>Amount</u> 1/	<u>Dollar Days</u>
Total 401(k) Match & Retirement Contribution		\$ 1,945,742 2/	\$ 32,381,154
Total 401(k) Administration Fees		1,398	127,849
Total ESPP Discount		26,607	557,948
Total ESPP Administration Fees		15,813	1,821,280
Total HSA Company Contribution		162,250	(28,356,500)
Total HSA Account Fees		8,232	72,322
Total Health Claims, Admin & Enrollment Fees		2,736,530	24,628,772
Total Active Vision		61,489	2,435,075
Total Executive Health Care Exams		9,225 3/	-
Total Active Life, AD&D, LTD		182,935	7,197,330
Total Active Dental		242,987	7,766,042
Total Employee Assistance Program		14,770	140,129
Total Aon Admin Fees		148,394	13,680,486
Retirees Pensions & Benefits Totals		3,446,372	92,426,848
Pension & Benefit Totals		<u>\$ 9,002,744</u>	<u>\$ 154,878,735</u>
Pension & Benefits Lag Days	<u>17.20</u>		

Notes:

1/ Exhibit VI, Item 18, pages 20 - 27.

2/ Schedule LKM-6, page 8.

3/ Schedule LKM-6, Page 9.

EQUITABLE GAS COMPANY

Calculation of 401(k) Match & Retirement Contribution Lag
For the Test Year Ended December 31, 2008

	<u>Payroll Period Begin</u>	<u>Payroll Period End</u>	<u>Mid Point of Service Period</u>	<u>Payment Date</u>	<u>Lag Days</u>	<u>Amount</u>	<u>Dollar Days</u>
<u>401(k) Match & Retirement Contribution</u>							
Total Per Company						\$ 1,945,742 1/	\$ 32,104,741 1/
Bonus Contribution per Co.	01/14/07 1/	01/27/07 1/	01/20/07 1/	02/06/07 1/	16.50 1/	(1,365) 1/	(22,523) 1/
Bonus Contribution per OCA	01/01/06	12/31/06	07/02/06	02/06/07	219.00 2/	1,365	298,935
Total 401(k) Match & Retirement Contribution Per OCA					16.64	<u>1,945,742</u>	<u>32,381,154</u>

Notes:

1/ Exhibit VI, Item 18, page

2/ Based on the response to OTS-RE-18-D.

EQUITABLE GAS COMPANY

Calculation of Executive Health Care Exams Lag
For the Test Year Ended December 31, 2008

<u>Payroll Period Begin</u>	<u>Payroll Period End</u>	<u>Mid Point of Service Period</u>	<u>Payment Date</u> 1/	<u>Lag Days</u>	<u>Amount</u> 1/	<u>Dollar Days</u>
<u>Executive Health Exams</u>						
01/04/07 2/	01/04/07 2/	01/04/07	01/04/07	0.00	\$ 1,825	\$ -
03/06/07 2/	03/06/07 2/	03/06/07	03/06/07	0.00	3,650	-
03/15/07 2/	03/15/07 2/	03/15/07	03/15/07	0.00	1,825	-
08/02/07 2/	08/02/07 2/	08/02/07	08/02/07	0.00	1,925	-
Totals				<u>0.00</u>	<u>\$ 9,225</u>	<u>\$ -</u>

Notes:

1/ Exhibit VI, Item 18, page 23.

2/ Response to OCA I-50.

EQUITABLE GAS COMPANY

Calculation of Taxes Other Than Income Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u>	<u>Amount</u>	<u>Dollar Days</u>
Combined Taxes Other Than Income Amounts Per Company		\$ 1,394,466 2/	\$ (92,099,751) 2/
Payroll Taxes	45.91 1/	<u>1,816,490 3/</u>	<u>83,394,657 4/</u>
Combined Taxes Other Than Income Amounts	<u>(2.71)</u>	<u>\$ 3,210,956</u>	<u>\$ (8,705,094)</u>

Notes:

- 1/ Exhibit VI, Item 18, page 12.
2/ Exhibit VI, Item 18, page 31.
3/ Exhibit III, Item § 53.53 III.A.17, Sheet 6.
4/ Lag days x Amount.

EQUITABLE GAS COMPANY

Adjustment to Annualize Operating Revenues
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Annualize Operating Revenues	<u>\$ 22,790,905 1/</u>
Adjustment to Operating Revenues	<u><u>\$ 22,790,905</u></u>

Notes:

1/ Adjustment Recommended by OCA Witness Glen Watkins.

EQUITABLE GAS COMPANY

Adjustment to Reverse Company's Adjustment to Include
Collection Costs in O&M Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Collection Costs Included in the Cost of Service	<u>\$ 612,202</u> 1/
Adjustment to O&M Expenses	<u><u>\$ (612,202)</u></u>

Notes:

1/ Exhibit III, Item § 53.53 III.A.17, Page 9.

EQUITABLE GAS COMPANY

Adjustment to Remove Excess Anode Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Excess Anode Expenses	<u>\$ 269,658 1/</u>
Adjustment to O&M Expenses	<u><u>\$ (269,658)</u></u>

Notes:

1/ Response to OCA I-19.

EQUITABLE GAS COMPANY

Adjustment to Normalize Customer Experience Study Costs
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Customer Experience Study Costs	\$ 795,858 1/
Normalization Period (Years)	<u>5</u>
Normalized Customer Experience Study Costs	\$ 159,172
Customer Experience Study Costs per Company	<u>795,858</u>
Adjustment to O&M Expenses	<u><u>\$ (636,686)</u></u>

Notes:

1/ Response to OCA I-26.

EQUITABLE GAS COMPANY

Adjustment to Annualize PA One Call Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Annual Costs at Contract Rate	\$ 506,313 1/
Internal Labor Costs	<u>(17,327) 2/</u>
Annulized PA One Call Expense	\$ 488,986
Annulized PA One Call Expense per Company	<u>572,183</u>
Adjustment to O&M Expenses	<u><u>\$ (83,197)</u></u>

Notes:

1/ Response to OCA I-20.

2/ Response to OCA I-21.

EQUITABLE GAS COMPANY

Adjustment to Remove Lobbying Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Lobbying Expenses Included in Corporate Allocation	\$ (122,009) 1/
Portion of AGA Dues Attributed to Lobbying	<u>(1,584) 2/</u>
Adjustment to O&M Expenses	<u><u>\$ (123,593)</u></u>

Notes:

1/ Response to OTS-RE-78-D.

2/ Exhibit VI, Standard Data Request, Volume 1, Item No.33.

EQUITABLE GAS COMPANY

Adjustment to Annualize Payroll Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
<u>Payroll Expenses</u>	
<u>Unfilled Positions</u>	
Compression Operator	\$ 45,531 1/
Compression Operator	45,531 1/
Producer Services Analyst	39,967 1/
Producer Services Engineer	65,000 1/
<u>Vacated Positions</u>	
Position # 99909180	<u>67,438 2/</u>
Adjustment to Payroll Expenses	<u>\$ (263,467)</u>
<u>Fringe Benefits Expenses</u>	
Total Fringe Benefits Percentage	29.97%
Total Decrease in Fringe Benefits Expenses	<u>\$ (78,961)</u>
Adjustment to O&M Expenses	<u><u>\$ (342,428)</u></u>

Notes:

1/ Response to OCA I-11.

2/ Responses to OCA IX-8 and OCA I-8.

EQUITABLE GAS COMPANY

Adjustment to Reflect Pension & Postretirement Benefits at the Ongoing Level
For the Test Year Ended December 31, 2008

	<u>Amount</u>	
2008 Total Pension Cost	\$ 594,491	1/
2008 Total Postretirement Benefits Cost	<u>1,807,247</u>	1/
Total Pension & Postretirement Benefits Costs	\$ 2,401,738	
Pennsylvania Percentage	<u>98.36%</u>	2/
Pennsylvania Pension & Postretirement Benefits Costs	\$ 2,362,349	
O&M Percentage	<u>84.40%</u>	
Pennsylvania Pension & Postretirement Benefits Expense	\$ 1,993,823	3/
PA Pension & Postretirement Benefits Expense per Company	<u>2,457,296</u>	4/
Adjustment to O&M Expenses	<u><u>\$ (463,473)</u></u>	

Notes:

1/ Response to OTS-RE-68-D.

2/ Standard Data Requests, Item 23.

3/ Standard Data Requests, Item 19.

4/ Response to OTS-RE-139-D.

EQUITABLE GAS COMPANY

Adjustment to Normalize Regulatory Commission Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Cost of the Current Rate Case	\$ 1,051,160 1/
Cost of the Service Life Study	<u>15,000 2/</u>
Total Rate Case	\$ 1,066,160
Normalization Period (Years)	<u>5</u>
Normalized Rate Case Expenses	\$ 213,232
Historical Test Year Regulatory Expenses	13,474 3/
Costs Related to West Virginia Matters	<u>(8,626) 4/</u>
Future Test Year Regulatory Expenses per OCA	\$ 218,080
Future Test Year Regulatory Expenses per Company	<u>516,861</u>
Adjustment to O&M Expenses	<u><u>\$ (298,781)</u></u>

Notes:

1/ Exhibit III, Item § 53.53 III.A.20 Sheet 2.

2/ Per OTS-RE-89-D, the total cost of the management audit and the service life study is \$765,000, and OCA IV-15 the management audit cost is \$750,000.

3/ Exhibit III, Item § 53.53 III.A.28 Sheet 7.

4/ Per response to OCA IV-8.

EQUITABLE GAS COMPANY

*Adjustment to Annualize the Increase in Cost of Fuel
For the Test Year Ended December 31, 2008*

	<u>Diesel Gallons</u>		<u>Gasoline Gallons</u>		<u>Totals</u>
January 2008 - August 2008 Fuel Usage	57,247	1/	178,709	1/	
Period Number of Months	8		8		
Annual Number of Months	<u>12</u>		<u>12</u>		
Annualized 2008 Fuel Usage	85,871		268,064		
2008 Price per Gallon	<u>\$ 4.00</u>	2/	<u>\$ 3.61</u>	2/	
Annualized Fuel Expense	\$ 343,482		\$ 967,709		\$ 1,311,191
Annualized Fuel Expense per Company	<u>392,391</u>	2/	<u>988,423</u>	2/	<u>1,380,814</u>
Adjustment to O&M Expenses	<u>\$ (48,909)</u>		<u>\$ (20,714)</u>		<u>\$ (69,623)</u>

Notes:

1/ Response to OCA VIII-18.

2/ Response to OCA I-17.

EQUITABLE GAS COMPANY

Adjustment to Normalize Injuries & Damages Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>	<u>Totals</u>
<u>Charges Against the Reserve (Claims)</u>		
2005 Charges Against the Reserve	\$ 235,769 1/	
2006 Charges Against the Reserve	256,243 1/	
2007 Charges Against the Reserve	<u>363,135 1/</u>	
Average		\$ 285,049
<u>Test Year Expense</u>		
2007 Expense Accrual	\$ 2,888,475 1/	
2007 Reserve Adjustments	(2,992,765) 1/	
Company's Pro Forma Normalization Adjustment	<u>3,145,292 1/</u>	
Net Injuries & Damages Expense		<u>3,041,002</u>
Adjustment to O&M Expenses		<u><u>\$(2,755,953)</u></u>

Notes:

1/ Response to OCA I-1.

EQUITABLE GAS COMPANY

Adjustment to Normalize Right of Way Mowing Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Customer Experience Study Costs	<u>\$ 384,431 1/</u>
Adjustment to O&M Expenses	<u><u>\$ (384,431)</u></u>

Notes:

1/ Response to OCA I-26.

EQUITABLE GAS COMPANY

Adjustment to Reverse Cathodic Protection Costs Related to DOT Compliance
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Cathodic Protection Costs	<u>\$ 133,524 1/</u>
Adjustment to O&M Expenses	<u><u>\$ (133,524)</u></u>

Notes:

1/ Response to OCA I-4.

EQUITABLE GAS COMPANY

Adjustment to Reflect OCA's Universal Service Costs adjustments
For the Test Year Ended December 31, 2008

	<u>Amount</u>	<u>1/</u>
Total Universal Service Adjustments per OCA		
Witness Colton	\$ 6,194,805	
CAP Administrative Costs	<u>299,194</u>	
Total Universal Service and Administrative		
Costs per OCA	\$ 6,493,999	
Total Universal Service and Administrative		
Costs per Company	<u>16,874,692</u>	
Adjustment to O&M Expenses	<u>\$ (10,380,693)</u>	

Notes:

1/ Schedule RDC-5.

EQUITABLE GAS COMPANY

Interest Synchronization Adjustment
For the Test Year Ended December 31, 2008

	<u>Amount</u>
OCA Rate Base	\$ 575,704,990 1/
Weighted Cost of Debt	<u>3.08%</u>
Adjusted Interest Deduction	\$ 17,731,714
Interest Deduction Per Company	<u>16,972,820 2/</u>
Adjustment to Synchronize Interest Expense	\$ 758,894
Effective State Income Tax Rate	<u>9.99%</u>
Adjustment to State Income Taxes	<u>\$ (75,814)</u>
Federal Income Tax Base	\$683,080
Federal Income Tax Rate	<u>35.00%</u>
Adjustment to Federal Income Taxes	<u>\$ (239,078)</u>

Notes:

1/ Schedule LKM-2, Page 1.

2/ Exhibit III, Item § 53.53 III.A.17, Sheet 8.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08

HBG, PA

RMS

Pennsylvania Public Utility Commission,

v.

Equitable Gas Company

Docket No. R-2008-2029325, et al

Independent Oil and Gas Association of
Pennsylvania

v.

Equitable Gas Company

C-20066800

SURREBUTTAL TESTIMONY OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

NOVEMBER 14, 2008

RECEIVED
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SECRETARY OF PUBLIC UTILITY

EXETER

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

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Introduction and Summary

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. I am a Senior Regulatory Analyst with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. ARE YOU THE SAME LAFAYETTE K. MORGAN, JR., WHO PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimonies of Equitable Gas Company's (Equitable or the Company) witnesses Gras, Ross and Mitchell.

Q. ARE YOU PRESENTING ANY SCHEDULES WITH YOUR SURREBUTTAL TESTIMONY?

A. Yes. I have attached Schedules LKM-1S through LKM-22S to this testimony. These schedules present the OCA's updated position regarding Equitable's requested rate increase. The recommendations reflected on the schedules attached to my testimony are based upon the Company's initial filing. After reviewing and analyzing the various revisions made by the Company and me, I have determined the appropriate change in Equitable's distribution revenues to be a \$31.4 million increase. This

1 revenue change is based upon the level of rate base and cost of service that I am
2 recommending and Mr. Parcell's recommended rate of return. When the cost of
3 service is adjusted to reflect OCA witness Colton's universal service adjustments, the
4 Company's revenue increase is \$25.7 million. If the Commission concludes that the
5 Company has not met its burden of proving the reasonableness of recovering the
6 negotiated rate discounts discussed by Mr. Watkins, the revenue increase would be
7 \$2.4 million.

8 **Post-Test Year Plant in Service Additions**

9 **Q. EQUITABLE'S WITNESS CAROL B. GRAS HAS ADDRESSED THE**
10 **ADJUSTMENT YOU MADE TO PLANT IN SERVICE RELATED**
11 **TO POST TEST YEAR ADDITIONS. WOULD YOU PLEASE**
12 **COMMENT?**

13 A. *In my direct testimony, I made an adjustment to remove the cost of certain stand-*
14 *alone assets that were treated as Construction Work in Progress (CWIP) as of the end*
15 *of the future test year by the Company and included in rate base as post-test year*
16 *plant additions occurring within six months after the end of the future test year.*
17 *Witness Gras has accepted my adjustment to remove those costs, which total*
18 *\$1,761,627, from rate base. However, she indicates that the depreciation expense*
19 *related to the \$1,761,627 of post-test year plant additions should also be removed*
20 *from the cost of service. I agree with Ms. Gras and have reflected a reduction of*
21 *\$74,118 in depreciation expense on Schedule LKM-22S. This is the same amount*
22 *removed by Ms. Gras.*

1 **Cash Working Capital**

2 **Q. EQUITABLE WITNESS DAVID W. ROSS DISAGREES WITH**
3 **SEVERAL OF THE ADJUSTMENTS YOU MADE TO THE**
4 **LEAD/LAG STUDY USED TO DETERMINE THE ALLOWANCE**
5 **FOR CASH WORKING CAPITAL. WOULD YOU PLEASE**
6 **SUMMARIZE THE AREAS OF DISAGREEMENT?**

7 A. Yes. Mr. Ross disagrees with the corrected lag days I calculated for Other O&M
8 expenses, short-term incentive compensation, 401(K) plan matching, Corporate
9 Services Expenses, Taxes Other Than Income, and the inclusion of the adjustment
10 proposed by OCA witness Colton. For each of these claims, he states that my
11 position is wrong and offers an explanation for his conclusion. I will address each of
12 his claims separately.

13 Mr. Ross' first claim relates to the correction of the Other O&M expenses lag
14 that I made to remove an error that was reflected in the Company's filing. This error
15 was created because the Company used the wrong payment date for services received
16 from one of its vendors, Sherman & Associates. It appears that Mr. Ross does not
17 disagree with how the correction was made to that specific vendor's payment
18 practice. Instead, he disagrees with the revised composite lag days for Other O&M
19 expenses (of which Sherman & Associates is one of the components) that I have
20 calculated. Mr. Ross has correctly determined that the retiree benefits lag was not
21 included in the revised Other O&M expense composite lag days I calculated. I agree
22 with his assessment and have properly included the retiree benefits in the Other O&M
23 expense lag presented on Schedule LKM-6S, page 5.

1 The second claim made by Mr. Ross involves the adjustment I made to the lag
2 days applied to the Short-Term Incentive Plan (STIP) compensation. Mr. Ross states
3 that my adjustment is wrong primarily because the STIP is wholly discretionary.
4 According to him the STIP is not “fixed nor incurred until the Company undertakes
5 and concludes its review after year end book closings in January, and only upon
6 consideration of many factors, which include but are not limited to employee
7 performance in the prior year.”¹ The overall conclusion of his position is that the
8 obligation to pay is not created until the Company concludes its review. Mr. Ross is
9 wrong for the reasons below.

10 **Q. WHY IS THE COMPANY’S TREATMENT OF THE SHORT-TERM**
11 **INCENTIVE PAY LAG DAYS WRONG?**

12 A. The primary reason the lag days calculated for the short-term incentive payment is
13 wrong is because Mr. Ross has used the wrong period of time as the service period
14 over which the STIP is earned. Specifically, Mr. Ross used the review period
15 (January 14-27, 2007, for the calendar year 2006) as the service period for the STIP
16 paid during January 2007. This period is incorrect when one considers the way the
17 STIP is designed. The keyword in the STIP (Short-Term Incentive Plan) is the word
18 “Incentive.” The plan is designed to create an incentive for individual employees to
19 work toward achievement of specific pre-established financial and operational goals
20 of the Company. In exchange for this effort, employees are eligible to receive bonus
21 compensation if the goals are achieved. (This bonus is sometimes addressed before
22 this Commission as “at-risk” pay.) In OCA interrogatory VIII-30, Equitable was

¹ Equitable Statement 8-R at 13.

1 asked whether the STIP payments made during January 2007 were compensation for
2 performance and goals achieved during the previous calendar year. In response, the
3 Company stated:

4
5 Yes, it is based upon the performance and goals achieved in the
6 previous calendar year, but bonuses are discretionary. The
7 company's main purpose in providing a bonus program is to
8 maintain a competitive level of total annual cash compensation
9 and to align the interest of the Company's employees with those
10 of the Company's shareholders, customers, and with the strategic
11 objective of the Company.

12
13 The STIP is discretionary because it is based in part on the overall
14 performance of the Company, the business segment in which the employees work,
15 and the individual contribution of each employee. The fact that the payment of
16 bonuses is discretionary is irrelevant to the calculation of the lag days, however.
17 What is relevant is the time period of employee service that forms that basis of the
18 incentive compensation. As long as the bonuses are paid and claimed in the cost of
19 service as an annual recurring expense, the expense payment lag must reflect the
20 actual service period and payment date consistent with the principles of the lead/lag

1 study.² The actual service period in this case is one year with the midpoint being July
2 2, 2006.

3 Moreover, the Commission should ignore Mr. Ross' claim that my lag day
4 calculation is wrong because of the discretionary nature of these costs. First, as
5 presented in Mr. Ross' rebuttal testimony, the payment of the short-term incentive
6 compensation is presented as if it is so uncertain that the payment is rare, occasional
7 or unusual. The Company's recent history does not support such a claim. Equitable
8 has made STIP payments every year for the last three years. (See the Company's
9 Exhibit VI, Volume 2, Item 26). Second, "discretionary" also means that
10 management has the latitude to vary the amount of money to be paid in incentives. In
11 other words, the amount of money available for STIP payments is not a fixed
12 percentage of base compensation or a fixed dollar amount. Instead, the total STIP
13 amount paid can fluctuate from year to year. For example, the incentive
14 compensation paid in a succeeding year could be less than the previous year if the
15 Company does not perform as well as the previous year.

16 Based on the foregoing, the Commission should reject the Company's
17 calculation of the lag days assigned to the STIP and accept the calculation I have
18 presented on Schedule-LKM-6S, pages 2 and 3.

19 **Q. PLEASE ADDRESS THE NEXT CLAIM MADE BY MR. ROSS IN**
20 **HIS DISCUSSION OF THE LEAD/LAG STUDY.**

² On page 7 of my direct testimony (corrected), I indicate that the expense lag measures from the midpoint of the service period to the payment date. On page 2, lines 1 through 5 of Mr. Ross' rebuttal testimony, he indicates the he agrees with my description of the method for calculating a lead/lag study.

1 A. Mr. Ross states that there should not be an adjustment to the 401(k) service lag for
2 Pennsylvania because the Company does not match the 401(k) contributions for STIP
3 in Pennsylvania. He explains that the Company has removed the 401(k) matching
4 expense of \$1,365 and the related dollar days of \$22,514 from the overall employee
5 benefits lag because those amounts are related to West Virginia employees. While
6 Mr. Ross presents this as a disagreement with my position, he is actually correcting
7 an error that was made by Equitable in its direct filing. I am accepting Mr. Ross'
8 correction of the Company's error. This change is reflected on Schedule LKM-6S,
9 page 8.

10 **Q. PLEASE ADDRESS THE NEXT CLAIM MADE BY MR. ROSS IN**
11 **HIS DISCUSSION OF THE LEAD/LAG STUDY.**

12 A. The next claim made by Mr. Ross relates to the Corporate Services Expense lag days.
13 In my direct testimony I explain why it is necessary to adjust the expense lag
14 associated with the Corporate Services Expense. To summarize, I changed the
15 expense lag days used for these expenses to reflect payment of these services as the
16 revenues were received. This change is necessary because the Company's responses
17 to interrogatories suggest that no cash payment is actually made to settle these
18 expenses on a monthly basis as is shown on the lag day calculation³ and that no bills
19 are submitted for these expenses. Mr. Ross is critical of my adjustment claiming each
20 affiliate is billed, and then a wire transfer is issued at the end of every month to settle
21 inter-company transactions. He also states that I am wrong to conclude that bills

³ Company Exhibit VI, Item 18, Page 3.

1 were estimates and presents a discussion in which he attempts to justify the existence
2 of the Corporate Services unit. I will now address each of these claims in turn.

3 Mr. Ross's rebuttal testimony claims are contradictory to the responses
4 provided by the Company to the OCA and OTS interrogatories. In the response to
5 OCA I-45, Equitable states that it does not receive a bill for the services it receives
6 and no actual cash payments were reflected on the schedule it used to calculate the
7 Corporate Services Expense lag days. Also in the response to OTS-RE-20-D (which
8 also refers to the schedule calculating the corporate services lag days), the Company
9 states that "[t]here are no third party invoices or checks. All these charges are settled
10 with all affiliated activity at month end." Based on his rebuttal testimony, Mr. Ross
11 has obviously narrowly defined cash payments to exclude wire transfer payments.
12 Wire transfer payments are essentially the movement of cash from one account to
13 another through electronic means. Given that he is now claiming that wire transfers
14 are made monthly, the burden is on the Company to provide the data in order to
15 properly reflect the payment lag. The actual wire transfer date must be matched with
16 the corresponding service period to properly calculate the expense lag days. The
17 OCA has requested the data from the Company and, if necessary, I will update our
18 position when received.

19 With regard to Mr. Ross' claim that I erroneously concluded that the bills
20 were estimates,⁴ as support for my conclusion that the bills were estimates, I
21 identified 8 of the 12 months as being the same amount. Yet, Mr. Ross admits that

⁴ Page 16, Lines 12 through 15 of Equitable Statement No. 8-R.

1 these expenses are estimates but argues that they are reconciled to actuals quarterly.

2 The fact remains that the bills that trigger payment are estimates.

3 It is important to note that my adjustment to the corporate services expenses in
4 the lead/lag study in no way denies the Company recovery of these expenses.
5 However, my calculation of the Corporate Services Expense lag days, on Schedule
6 LKM-6S, page 4, should be accepted by the Commission.

7 **Q. WHAT IS THE NEXT CLAIM MADE BY MR. ROSS?**

8 A. The next claim discussed by Mr. Ross involves the inclusion of the payroll taxes and
9 the corresponding lag days in the calculation of Taxes Other Than Income lag days.
10 In my direct testimony, I included the payroll taxes lag days in the calculation of the
11 composite Taxes Other Than Income lag days. Mr. Ross has adequately
12 demonstrated that the payroll taxes are not included in the Taxes Other Than Income
13 amount in the lead/lag study. Therefore, my adjustment on Schedule LKM-6S, page
14 10 is not necessary and will be withdrawn.

15 **Q. WHAT IS THE LAST CLAIM MADE BY MR. ROSS?**

16 A. The last claim made by Mr. Ross involves the universal service cost adjustment
17 proposed by OCA witness Colton, which I have reflected in the lead/lag study. Mr.
18 Ross points out that universal service costs are recorded as uncollectible expense on
19 the Company's books. After further review of this issue, I will revise my adjustment
20 and treat Mr. Colton's adjustment in a manner that is consistent with uncollectible
21 expenses. As a result of revising my adjustment, Mr. Ross and I are in agreement on
22 the manner in which Mr. Colton's universal service adjustments are reflected in the
23 lead/lag study.

1 **Collection Costs**

2 **Q. EQUITABLE WITNESS JEFFREY C. MITCHELL STATES THAT**
3 **HE DISAGREES WITH YOUR ADJUSTMENT TO REMOVE THE**
4 **COMPANY'S COLLECTION COSTS CLAIM FROM THE COST OF**
5 **SERVICE. PLEASE RESPOND TO THE CLAIMS MADE BY MR.**
6 **MITCHELL IN REBUTTAL TESTIMONY.**

7 A. In my direct testimony, I describe the collection costs as costs that were accumulated
8 since the Company's last rate case, which were deferred, and that the Company was
9 attempting to recover these costs in the rates set in this proceeding. My depiction of
10 these costs was based upon my understanding of the Company's responses to the
11 OCA interrogatories in light of the conventional accounting for such costs.
12 Collection costs are "period costs," meaning that they are reflected in operating
13 expenses in the period in which they are incurred. In that regard, my understanding
14 of collection costs is consistent with Mr. Mitchell's, as he described them as amounts
15 paid to third party collection agencies as compensation for the collection of accounts
16 receivable that were previously written off by the Company. Given that collection
17 costs are period costs, one would expect a direct charge to expenses to record the
18 collection costs. However, as Mr. Mitchell states in rebuttal testimony, the collection
19 costs are indirectly charged to operating expenses as a part of uncollectible expense.
20 This indirect method of expense recognition and the Company's responses to OCA I-
21 9, VIII-12 and VIII-13 led to my conclusion that the Company had treated the costs as
22 deferred costs and was attempting to recover the deferred costs in this proceeding.
23 Nevertheless, I stated in my direct testimony that the OCA had an outstanding data

1 request on this issue which, if necessary, could lead to a revision of my adjustment.
2 After reviewing the response to that data request and Mr. Mitchell's rebuttal
3 testimony, I have determined that my adjustment should remain unchanged, but the
4 reason the adjustment is necessary has changed based upon the additional data.

5 **Q. WHY IS THE ADJUSTMENT YOU MADE NECESSARY?**

6 The adjustment is necessary because as Mr. Mitchell states on page 5, lines 23 and
7 24, "the collections costs are indirectly recognized in the income statement." As a
8 result, no additional recovery of these costs is necessary. In that section of Mr.
9 Mitchell's rebuttal testimony, he provides a theoretical example that demonstrates
10 how collections costs are recorded. In short, since collection costs reduce the
11 accounts receivable reserves, it requires a higher uncollectible expense (equal to the
12 same amount of the collection costs) be recorded to replenish the accounts receivable
13 reserve that collection costs was charged against. The higher uncollectible expense is
14 how the collection costs are reflected in operating expenses and recovered by
15 Equitable.

16 **Anode Expenses**

17 **Q. MR. MITCHELL STATES THAT HE DISAGREES WITH YOUR**
18 **ADJUSTMENT TO REMOVE THE REMAINING \$269,658 OF**
19 **ANODE EXPENSES FROM OPERATING EXPENSES. PLEASE**
20 **RESPOND TO HIS REBUTTAL TESTIMONY ON THIS ISSUE.**

21 A. Beginning on page 16 of my direct testimony, I explain in detail the reason for
22 removing \$269,658 from the cost of service for anode expenses. However, to
23 summarize, Equitable incurred \$1,269,658 of costs related to cathodic protection of

1 pipes. Under the Company's new accounting policy, these costs will now be
2 capitalized rather than expensed. The Company removed only \$1,000,000 of these
3 costs and left the remaining \$269,658 in the cost of service. Mr. Mitchell claims in
4 his rebuttal testimony that the \$269,658 represents the estimated cost for routine
5 inspection and maintenance even though the Company had identified these costs as
6 capital costs under the new accounting policy.⁵

7 I disagree with the Company for the following two reasons. First, the
8 Company already has costs of nearly \$2.9 million in the cost of service relating to
9 inspection of corrosion and leaks. Hence, my position does not deny the Company
10 the ability to recover such substantiated costs. Second, the Company was asked to
11 demonstrate that a portion of the \$1,269,658 was related activity that was not to be
12 capitalized under its new policy.⁶ The response given by the Company was
13 essentially the same as the explanation given in Mr. Mitchell's rebuttal testimony.
14 Consequently, the Commission should reject the Company's claim for the additional
15 cost of \$269,658 relating to inspection of corrosion and leaks.

16 **Pension Expense**

17 **Q. DO YOU AGREE WITH THE REVISION TO PENSION EXPENSE**
18 **THAT MR. MITCHELL HAS MADE IN HIS REBUTTAL**
19 **TESTIMONY?**

20 **A.** Conceptually, I am in agreement with Mr. Mitchell on this issue. However, the
21 pension costs have increased dramatically from the amount that was provided during

⁵ Equitable Statement No. 2-R at 6.

⁶ OCA Interrogatory XII-5

1 my analysis of these costs. Mr. Mitchell did not include the supporting actuarial
2 study for the revised pension expense that the Company is now claiming. A request
3 has been made to the Company for a copy of the actuarial study. The OCA reserves
4 the right to amend its position on this issue pending review of the pension actuarial
5 study.

6 **Fuel Expense**

7 **Q. DO YOU AGREE WITH THE COMPANY'S CURRENT POSITION**
8 **ON FUEL EXPENSE?**

9 A. No. The only difference between the Company and the OCA regarding fuel costs is
10 the price of diesel fuel. In the Company's direct filing, the Company used a price of
11 \$4.00 per gallon for diesel fuel, but Mr. Mitchell is now revising the Company's
12 claim at \$4.24 per gallon. The Company cited the AAA Daily Fuel Gauge Report,
13 May 5, 2008, as the source of the prices it used in its adjustment. The Daily Fuel
14 Gauge Report, November 13, 2008, for the Pittsburgh area reports a current diesel
15 price of \$3.31 per gallon. This amount is less than the \$4.00 price I used in my
16 testimony (and also used by Equitable in its direct filing). Using a price that is \$0.69
17 (\$4.00-\$3.31) per gallon more than the current price of diesel fuel is reasonable
18 because the Energy Information Administration (EIA) of the Department of Energy
19 has stated that the global economic downturn has resulted in a substantial reduction in
20 crude oil demand and prices. The EIA is projecting diesel fuel in 2009 to be \$2.73
21 per gallon, or a 28.3 percent decrease from 2008. (See Attachment A) I recognize
22 that fuel prices vary at the local level, but I have cited the EIA's forecast to
23 demonstrate the projected downward price trend. Another way to demonstrate the

1 reasonableness of my adjustment is to recognize that I have used a price per gallon
2 that is \$0.69 per gallon higher than current prices to allow for price volatility.
3 Therefore, the Commission should not accept the \$4.24 price per gallon that Mr.
4 Mitchell has included in his rebuttal testimony.

5
6 **Injuries & Damages Expense**

7 **Q. MR. MITCHELL HAS REVISED THE COMPANY'S INJURIES AND**
8 **DAMAGES CLAIM IN HIS REBUTTAL TESTIMONY. DO YOU**
9 **AGREE WITH THE COMPANY'S CURRENT POSITION?**

10 **A.** In the Company's direct filing, the injuries and damages claim was determined by an
11 adjustment that removed costs that the Company deemed to be one-time costs. The
12 annual adjustment to injuries and damages reserve was incorrectly considered to be a
13 *one-time adjustment by Equitable and removed from operating expenses. With*
14 regard to legal settlements, the historical test year did contain an extraordinarily high
15 level of payment in comparison to previous years. The legal settlements paid by the
16 Company for 2005, 2006, and 2007 were \$108,750, \$311,680, and \$3,960,828,
17 respectively. The reason for the significantly higher payment of \$3,960,828 during
18 2007 is the result of a gas explosion rather than routine legal settlements. In its direct
19 filing, the Company appropriately removed the cost of the event from the cost of
20 service to determine the operating expenses on an ongoing basis. Mr. Mitchell has
21 accepted my approach of using the actual three-year average for injuries and damages
22 claims, and proposes a similar approach for legal settlements. In my direct testimony,
23 I disagreed with Equitable's treatment of the annual adjustment to the injuries and

1 damages reserve as a one-time event, but accepted the removal of the settlement
2 related to the gas explosion as a one-time event.

3 In Mr. Mitchell's rebuttal testimony, Equitable changed its position with
4 regard to recovery of these costs. Mr. Mitchell agrees with my approach of using a
5 three-year average for the injuries and damages claims, and he proposes, on the basis
6 of consistency, to normalize the legal settlement payments over a three-year period as
7 well. However, his three-year normalization approach differs from mine in that he is
8 seeking to use a partially projected year.

9 Although I have not changed the position outlined in my direct testimony, in
10 an effort to simplify the resolution of the injuries and damages expense issue, I would
11 accept a three-year normalization of the legal settlements at the actual historical
12 amounts rather than the use of a partially projected year in the normalization of these
13 costs for purposes of this case.

14 **Q. DOES THIS END YOUR SURREBUTTAL TESTIMONY?**

15 A. Yes. However, as previously, I reserve the right to revise this testimony upon receipt
16 of additional information requested from the Company.

17
18
19 00106429.doc

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

ATTACHMENT A

TO THE

SURREBUTTAL TESTIMONY OF

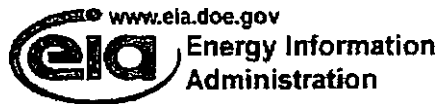
LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

NOVEMBER 14, 2008

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



November 2008

Short-Term Energy Outlook

November 12, 2008 Release

Highlights

- The current U.S. and global economic downturn has led to a decrease in global energy demand and a rapid and substantial reduction in crude oil and other energy prices. As a result, projections for both energy demand and prices are considerably lower than last month's *Outlook*.
- The monthly average price of West Texas Intermediate (WTI) crude oil fell from over \$133 per barrel in July to about \$77 per barrel in October, indicative of the abrupt decline in world petroleum demand growth. The annual average WTI price is now projected to be \$101.45 per barrel in 2008 and \$63.50 in 2009.
- The average U.S. prices for regular-grade gasoline and diesel fuel, at \$2.22 and \$2.94 per gallon respectively on November 10, were both more than \$1.80 per gallon below their highs in mid-July. With a weak economy continuing through most of 2009, along with lower projected crude oil prices, the annual average retail gasoline and diesel prices in 2009 are projected to be \$2.37 and \$2.73 per gallon, respectively.
- Residential heating oil prices during the current heating season (October through March) are projected to average \$2.75 per gallon, a reduction of about 17 percent from the 2007-2008 heating season. Residential propane prices are projected to average \$2.22 this winter, a decrease of 10 percent from last winter. Residential natural gas prices are projected to average \$13.02 per thousand cubic feet (Mcf), an increase of 2 percent from last winter.
- The impact of the economic downturn on demand is also lowering current and expected natural gas prices. The Henry Hub natural gas spot price is projected to average \$9.27 per Mcf in 2008. The projected 2009 annual average Henry Hub price is \$6.82 per Mcf compared with \$8.17 in the previous *Outlook*.



Short-Term Energy Outlook

November 12, 2008 Release
(Next Update: December 9, 2008)Printer-friendly versions:
Full Report Text Only Tables Only
Charts Only[Highlights](#) | [Global Petroleum](#) | [U.S. Petroleum](#) | [Natural Gas](#)
| [Electricity](#) | [Coal](#)

Highlights

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Economic Outlook

The recent dramatic deterioration in the outlook for economic growth in the United States and the rest of the world has led to a significant reduction in this *Outlook's* assumptions for world economic growth and projections of energy demand and prices. World real gross domestic product (GDP) growth is projected to slow from about 4 percent in 2006 and 2007 to about 2.5 percent this year and 1.8 percent in 2009. Last month's *Outlook* assumed world GDP would increase by 3.0 percent in 2008 and by 2.8 percent in 2009. Previous lows for world economic growth were 0.3 percent in 1982, 1.7 percent in 1993, and 1.5 percent in 2001.

The year-over-year changes in U.S. real GDP in last month's *Outlook* were 1.8 percent growth in 2008 and 0.8 percent growth in 2009. U.S. real GDP growth in the current *Outlook* has been lowered to 1.3 percent for 2008 and is projected to decline by 1.4 percent in 2009. The 2009 average unemployment rate has been raised from 6.2 percent to 7.9 percent in this forecast. The U.S. manufacturing production index was lowered by 1.1 percent and 7.0 percent for 2008 and 2009, respectively, with the 2009 growth rate of the index falling from a positive 0.5 percent (growth) to negative 5.5 percent (decline).

Global Petroleum

Price Summary

	Year				Percent Change		
	2006	2007	2008	2009	06-07	07-08	08-09
WTI							
Crude ^a (\$/barrel)	66.02	72.32	101.45	63.50	9.5	40.3	-37.4
Gasoline ^b (\$/gal)	2.68	2.81	3.29	2.37	8.9	17.4	-28.0
Diesel ^c (\$/gal)	2.70	2.88	3.81	2.73	6.6	32.2	-28.3
Heating Oil ^d (\$/gal)	2.48	2.72	3.36	2.63	9.5	23.5	-21.7
Natural Gas ^d (\$/mcf)	13.76	13.00	13.74	12.55	-5.4	5.7	-8.7

^a West Texas Intermediate^b Average regular pump price^c On-highway retail^d Residential average

Detailed STEO Information:

- * [Query STEO database assumptions, data, projections](#)
- * [Real Petroleum Prices](#) charts, data, projections

Related STEO Information:

- * [STEO Release Schedule](#)
- * [Previous STEO Outlooks](#)
- * [Special Analyses and Model Documentation](#)
- * [Contact STEO Experts](#)

Other EIA Forecasts:

- * [U.S. Annual Energy Outlook](#)
- * [International Energy Outlook](#)

Tables

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pdf - printer-friendly table
All Tables in a single Excel file

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Figures gif - chart only

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

SCHEDULES TO THE
SURREBUTTAL TESTIMONY OF
LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

NOVEMBER 14, 2008

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

EQUITABLE GAS COMPANY

Summary of Operating Income
For the Test Year Ended December 31, 2008

	PAPUC Jurisdictional Amount per Co.	OCA Cost of Service Adjustments	Amount After Adjustments	OCA Recommended Change In Revenue	After Proposed Revenue Change
<u>Operating Revenues</u>					
Total Operating Revenues	\$ 516,617,530	\$ 22,790,905	\$539,408,435	\$ 2,385,882 1/	\$ 541,794,317
<u>Operating Expenses</u>					
Purchased Gas Costs	\$ 359,315,773	\$ -	\$359,315,773	\$ -	\$ 359,315,773
Non-purchased Gas Costs	105,108,151	(9,823,304)	95,284,847	50,489	95,335,336
Depreciation & Amortization Expenses	23,471,055	(74,118)	23,396,937	-	23,396,937
Taxes Other Than Income	2,185,866	-	2,185,866	6,576	2,192,442
Current Federal Income Tax	(3,182,873)	10,043,026	6,860,153	232,649	7,092,802
Current State Income Tax	(1,009,313)	3,184,719	2,175,406	733,659	2,909,065
Deferred Federal Income Taxes	8,545,747	-	8,545,747	-	8,545,747
Investment Tax Credit	(5,529)	-	(5,529)	-	(5,529)
Total Operating Expenses	\$ 494,428,877	\$ 3,330,323	\$497,759,200	\$ 1,023,373	\$ 498,782,573
Net Operating Income	\$ 22,188,653	\$ 19,460,582	\$ 41,649,235	\$ 1,362,509	\$ 43,011,744
Rate Base	\$ 583,252,590		\$577,339,819		\$ 577,339,819
Return On Rate Base	3.80%		7.21%		7.45%

Notes:

1/ This summary schedule reflects the adjustments related to universal service costs and negotiated rate discounts.

EQUITABLE GAS COMPANY

Summary of Revenue Increase at OCA Rate of Return
For the Test Year Ended December 31, 2008

		<u>Amount</u>	<u>Source</u>
Adjusted Rate Base		\$ 577,339,819	Schedule LKM-2, Page 2
Required Rate of Return		<u>7.450%</u>	
Net Operating Income Required		\$ 43,011,817	
Net Operating Income at Present Rates		<u>41,649,235</u>	Schedule LKM-1, Page 1
Income Deficiency/(Surplus)		\$ 1,362,582	
Revenue Multiplier		<u>1.751</u>	
Required Change in Company Revenue		<u>\$ 2,385,882</u>	
Proposed Revenue Change		\$ 2,385,882	
Uncollectibles	1.920%	45,809	
PUC, OCA, OSBA Assessments	0.281%	6,576	
LIURP	0.200%	<u>4,680</u>	
Subtotal		\$ 2,328,817	
State Income Tax	9.99%	<u>232,649</u>	
Subtotal		\$ 2,096,168	
Federal Income Tax	35.00%	<u>733,659</u>	
Net Income Increase Required		<u>\$ 1,362,509</u>	

EQUITABLE GAS COMPANY

Summary of Rate Base
For the Test Year Ended December 31, 2008

	PAPUC Jurisdictional Amount per Co.	OCA Rate Base Adjustments	Amount After Adjustments
Total Plant in Service	\$ 897,954,727	\$ (1,761,627)	\$ 896,193,100
Accumulated Depreciation	(289,353,072)	-	(289,353,072)
Net Plant in Service	\$ 608,601,655	\$ (1,761,627)	\$ 606,840,028
<u>Additions:</u>			
Materials & Supplies	\$ 887,426	\$ -	\$ 887,426
Current Gas Storage	75,175,769	-	75,175,769
Cash Working Capital	11,335,335	(4,151,144)	7,184,191
Prepayments	234,270	-	234,270
Total Additions	\$ 87,632,800	\$ (4,151,144)	\$ 83,481,656
<u>Deductions:</u>			
Accumulated Deferred Income Taxes	\$ (104,709,261)	\$ -	\$ (104,709,261)
Income Tax Credits	(4,902,910)	-	(4,902,910)
Customer Advances	-	-	-
Customer Deposits	(3,369,694)	-	(3,369,694)
Total Deductions	\$ (112,981,865)	\$ -	\$ (112,981,865)
Total Rate Base	<u>\$ 583,252,590</u>	<u>\$ (5,912,771)</u>	<u>\$ 577,339,819</u>

EQUITABLE GAS COMPANY

Summary of Rate Base Adjustments
For the Test Year Ended December 31, 2008

	<u>Source</u>	<u>PAPUC Jurisdictional Amount per Co.</u>
Rate Base per Company Filing	Schedule LKM-2, Page 1	<u>\$ 583,252,590</u>
<u>OCA Adjustments:</u>		
Plant in Service	Schedule LKM-5	\$ (1,761,627)
Cash Working Capital	Schedule LKM-6	<u>(4,151,144)</u>
Total Ratemaking Adjustments		<u>\$ (5,912,771)</u>
Adjusted Rate Base per OCA		<u><u>\$ 577,339,819</u></u>

EQUITABLE GAS COMPANY

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Net Income per Company	<u>\$ 22,188,653</u>
<u>OCA Adjustments:</u>	
Annualize Operating Revenues	\$ 13,334,161
Reverse Company's Collection Cost Adjustment	358,178
Remove Excess Anode Expenses	157,767
Normalize Customer Experience Study Costs	372,503
Annualize PA One Call Expense	18,060
Remove Lobbying Expenses	927
Annualize Payroll Expenses	79,818
Reflect Ongoing Level of Pension & OPEB Costs	271,162
Normalize Regulatory Commission Expenses	174,806
Annualize the Increase in Cost of Fuel	40,734
Normalize Injuries & Damages Expense	757,972
Normalize Right of Way Mowing Expense	198,811
Reverse Cathodic Protection Costs	78,120
Universal Service Costs per OCA	3,238,414
Interest Synchronization	335,785
Depreciation Expense	<u>43,364</u>
Total Ratemaking Adjustments	<u>\$ 19,460,582</u>
Total Adjusted Net Income per OCA	<u><u>\$ 41,649,235</u></u>

EQUITABLE GAS COMPANY

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2008

	Operating Revenues	O&M Expenses	Depreciation & Amortization Expenses	Taxes Other Than Income	Current State Income Tax	Current Federal Income Taxes	Deferred Income Taxes	Investment Tax Credit	Net Operating Income
PA Jurisdictional Amount per Company	\$ 516,617,530	\$464,423,924	\$ 23,471,055	\$ 2,185,866	\$ (1,009,313)	\$ (3,182,873)	\$ 6,545,747	\$ (5,529)	\$ 22,188,653
<u>OCA Adjustments:</u>									
Annualize Operating Revenues	\$ 22,790,905	\$ -	\$ -	\$ -	\$ 2,276,811	\$ 7,179,933	\$ -	\$ -	\$ 13,334,161
Reverse Company's Collection Cost Adjustment	-	(612,202)	-	-	61,159	192,865	-	-	358,178
Remove Excess Anode Expenses	-	(269,658)	-	-	26,939	84,952	-	-	157,767
Normalize Customer Experience Study Costs	-	(636,686)	-	-	63,605	200,578	-	-	372,503
Annualize PA One Call Expense	-	(30,868)	-	-	3,084	9,724	-	-	18,060
Remove Lobbying Expenses	-	(1,584)	-	-	158	499	-	-	927
Annualize Payroll Expenses	-	(136,426)	-	-	13,629	42,979	-	-	79,818
Reflect Ongoing Level of Pension & OPEB Costs	-	(463,473)	-	-	46,301	146,010	-	-	271,162
Normalize Regulatory Commission Expenses	-	(298,781)	-	-	29,848	94,127	-	-	174,806
Annualize the Increase in Cost of Fuel	-	(69,623)	-	-	6,955	21,934	-	-	40,734
Normalize Injuries & Damages Expense	-	(1,295,534)	-	-	129,424	408,138	-	-	757,972
Normalize Right of Way Mowing Expense	-	(339,810)	-	-	33,947	107,052	-	-	198,811
Reverse Cathodic Protection Costs	-	(133,524)	-	-	13,339	42,065	-	-	78,120
Universal Service Costs per OCA	-	(5,535,135)	-	-	552,960	1,743,761	-	-	3,238,414
Interest Synchronization	-	-	-	-	(80,844)	(254,941)	-	-	335,785
Depreciation Expense	-	-	(74,118)	-	7,404	23,350	-	-	43,364
Total Ratemaking Adjustments	\$ 22,790,905	\$ (9,823,304)	\$ (74,118)	\$ -	\$ 3,184,719	\$ 10,043,026	\$ -	\$ -	\$ 19,460,582
Total Adjusted Income	\$ 539,408,435	\$454,600,620	\$ 23,396,937	\$ 2,185,866	\$ 2,175,406	\$ 8,860,153	\$ 8,545,747	\$ (5,529)	\$ 41,649,235

EQUITABLE GAS COMPANY

**Reconciliation of Current State and Federal Income Taxes
For the Test Year Ended December 31, 2008**

	<u>Test Year Per Company</u>	<u>Ratemaking Adjustments</u>	<u>Test Year at Present Rates</u>	<u>Increase at OCA Rate of Return</u>	<u>After Proposed Revenue Change</u>
CALCULATION OF COMBINED CURRENT INCOME TAX					
Net Operating Income Before Income Taxes	\$ 26,536,685	\$ 32,688,327	\$ 59,225,012	\$ 2,328,817	\$ 61,553,829
<u>Adjustments for Income Taxes</u>					
Interest Expense	(16,972,820)	(809,246)	(17,782,066)	-	(17,782,066)
Book Depreciation Expense	23,471,055	-	23,471,055	-	23,471,055
Tax Depreciation Expense	(43,138,325)	-	(43,138,325)	-	(43,138,325)
State Taxable Income	<u>\$ (10,103,405)</u>	<u>\$ 31,879,081</u>	<u>\$ (19,667,270)</u>	<u>\$ 2,328,817</u>	<u>\$ (19,667,270)</u>
State Income Tax	9.99% <u>\$ (1,009,330)</u>	<u>\$ 3,184,720</u>	<u>\$ (1,964,760)</u>	<u>\$ 232,649</u>	<u>\$ (1,964,760)</u>
Federal Taxable Income Before State Income Tax	\$ (10,103,405)	\$ 31,879,081	\$ 21,775,676	\$ 2,328,817	\$ 24,104,493
State Income Tax	<u>(1,009,330)</u>	<u>3,184,720</u>	<u>2,175,390</u>	<u>232,649</u>	<u>2,408,039</u>
Federal Taxable Income	\$ (9,094,075)	\$ 28,694,361	\$ 19,600,286	\$ 2,096,168	\$ 21,696,454
Federal Income Tax	35.00% (3,182,926)	10,043,026	6,860,100	733,659	7,593,759
Federal Tax Credits	(5,529)	-	(5,529)	-	(5,529)
Net Federal Income Tax	<u>\$ (3,188,455)</u>	<u>\$ 10,043,026</u>	<u>\$ 6,854,571</u>	<u>\$ 733,659</u>	<u>\$ 7,588,230</u>
Net Combined Current Income Tax	\$ (4,197,785)	\$ 13,227,746	\$ 9,029,961	\$ 966,308	\$ 9,996,269
Total Combined Current Income Taxes (Schedule LKM-1, Page 1)	<u>(4,197,715)</u>	<u>13,227,745</u>	<u>9,030,030</u>	<u>966,308</u>	<u>9,996,338</u>
Unreconciled/Rounding	<u>\$ (70)</u>	<u>\$ 1</u>	<u>\$ (69)</u>	<u>\$ (0)</u>	<u>\$ (69)</u>

EQUITABLE GAS COMPANY

Adjustment to Plant in Service
For the Test Year Ended December 31, 2008

	<u>Amount</u>
<u>Post-Test Year plant in Service</u>	
Purchase New Meters and Regulators	\$ 636,394 1/
Tools and Equipment	242,451 1/
PC and Laptop Replacement	141,000 1/
Automotive Replacements	<u>741,782 1/</u>
Total Adjustment to Plant in Service	<u><u>\$ 1,761,627</u></u>

Notes:

1/ Response to OCA IV-26.

EQUITABLE GAS COMPANY

Adjustment to Allowance for Cash Working Capital
For the Test Year Ended December 31, 2008

	Pro Forma Expenses	1/	OCA Adjustments	Adjusted Pro Forma Expenses	Daily Requirement	Revenue Lag Days	1/	Expense Lag days	1/	Net Lag Days	Working Capital Requirement
<u>Operating Expense</u>											
Purchased Gas	\$ 359,315,773		\$ -	\$ 359,315,773	\$ 984,427	49.29		45.91		3.38	\$ 3,327,363
Payroll	24,095,087		(104,967)	23,990,120	65,726	49.29		45.91	2/	3.38	222,168
Employee Benefits	7,069,423		(487,017)	6,582,406	18,034	49.29		17.17		32.12	579,200
Corporate Services	15,990,000		-	15,990,000	43,808	49.29		49.29		-	-
Injuries & Damages	4,803,788		(1,295,534)	3,508,254	9,612	49.29		(164.74)		214.03	2,057,256
Uncollectibles	25,049,825		45,809	25,095,634	68,755	49.29		49.29		-	-
Other O&M Expenses	28,100,026		(2,388,056)	25,711,970	70,444	49.29		35.49		13.80	971,811
	<u>\$ 464,423,922</u>			<u>\$ 460,194,157</u>							
Depreciation & Amortization	23,471,055		(74,118)	23,396,937	-						-
Taxes Other Than Income	2,185,866		(1,339)	2,184,527	5,985	49.29		(66.05)	3/	115.34	690,290
<u>Income Taxes</u>											
Current Federal	(3,182,873)		10,275,675	7,092,802	19,432	49.29		36.50		12.79	248,540
Current State	(1,009,313)		3,918,378	2,909,065	7,970	49.29		51.58		(2.29)	(18,251)
Deferred Federal & State	8,545,747		-	8,545,747							
Investment Tax Credit	(5,529)		-	(5,529)	-						-
Interest on Debt	16,972,650		809,416	17,782,066	48,718	49.29		72.58		(23.29)	(1,134,642)
Sales and Use Taxes	6,287,006		-	6,287,006	17,225	49.29		35.33		13.96	240,456
Cash Working Capital per OCA											\$ 7,184,191
Cash Working Capital per Company											<u>11,335,335</u>
Adjustment to Cash Working Capital											<u>\$ (4,151,144)</u>

Notes:

- 1/ Exhibit VI, Item 18, page 2.
2/ Schedule LKM-5, page 3.
3/ Schedule LKM-5, page 10.

EQUITABLE GAS COMPANY

Calculation of Non-Union Payroll Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	1/ Lag Days	1/ Amount	1/ Dollar Days
12/18/06	12/31/06	12/24/06	01/10/07	16.50	\$ 663,113	\$ 10,941,365
01/01/07	01/14/07	01/07/07	01/24/07	16.50	663,604	10,949,466
01/01/06	12/31/06 2/	07/02/06	02/06/07	219.00	3,650,116 2/	799,375,404
01/15/07	01/28/07	01/21/07	02/07/07	16.50	665,254	10,976,691
01/29/07	02/11/07	02/04/07	02/21/07	16.50	656,666	10,834,989
02/12/07	02/25/07	02/18/07	03/07/07	16.50	650,454	10,732,491
02/26/07	03/11/07	03/04/07	03/21/07	16.50	682,704	11,264,616
03/12/07	03/25/07	03/18/07	04/04/07	16.50	658,826	10,870,629
03/26/07	04/08/07	04/01/07	04/18/07	16.50	657,239	10,844,444
04/09/07	04/22/07	04/15/07	05/02/07	16.50	663,850	10,953,525
04/23/07	05/06/07	04/29/07	05/16/07	16.50	669,857	11,052,641
05/07/07	05/20/07	05/13/07	05/30/07	16.50	664,132	10,958,178
05/21/07	06/03/07	05/27/07	06/13/07	16.50	666,519	10,997,564
06/04/07	06/17/07	06/10/07	06/27/07	16.50	663,067	10,940,606
06/18/07	07/01/07	06/24/07	07/11/07	16.50	664,892	10,970,718
07/02/07	07/15/07	07/08/07	07/25/07	16.50	662,533	10,931,795
07/16/07	07/29/07	07/22/07	08/08/07	16.50	649,673	10,719,605
07/30/07	08/12/07	08/05/07	08/22/07	16.50	648,531	10,700,762
08/13/07	08/26/07	08/19/07	09/05/07	16.50	635,798	10,490,667
08/27/07	09/09/07	09/02/07	09/19/07	16.50	640,692	10,571,418
09/10/07	09/23/07	09/16/07	10/03/07	16.50	591,651	9,762,242
09/24/07	10/07/07	09/30/07	10/17/07	16.50	593,444	9,791,826
10/08/07	10/21/07	10/14/07	10/31/07	16.50	596,533	9,842,795
10/22/07	11/04/07	10/28/07	11/14/07	16.50	598,294	9,871,851
11/05/07	11/18/07	11/11/07	11/28/07	16.50	590,987	9,751,286
11/19/07	12/02/07	11/25/07	12/12/07	16.50	629,265	10,382,873
12/03/07	12/16/07	12/09/07	12/26/07	16.50	589,239	9,722,444
				<u>52.79</u>	<u>\$ 20,366,933</u>	<u>\$ 1,075,202,885</u>

Notes:

1/ Exhibit VI, Item 18, page 11.

2/ Company response to OTS-RE-18-D.

EQUITABLE GAS COMPANY

Calculation of Union Payroll Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	1/ Lag Days	1/ Amount	1/ Dollar Days
12/18/06	12/31/06	12/24/06	01/12/07	18.50	\$ 393,762	\$ 7,284,597
01/01/07	01/14/07	01/07/07	01/26/07	18.50	386,120	7,143,220
01/01/06	12/31/06 2/	07/02/06	02/06/07	219.00	656,326	143,735,394
01/15/07	01/28/07	01/21/07	02/09/07	18.50	369,857	6,842,355
01/29/07	02/11/07	02/04/07	02/23/07	18.50	374,081	6,920,499
02/12/07	02/25/07	02/18/07	03/09/07	18.50	387,408	7,167,048
02/26/07	03/11/07	03/04/07	03/23/07	18.50	373,400	6,907,900
03/12/07	03/25/07	03/18/07	04/04/07	16.50	330,927	5,460,296
03/26/07	04/08/07	04/01/07	04/20/07	18.50	351,323	6,499,476
04/09/07	04/22/07	04/15/07	05/04/07	18.50	347,062	6,420,647
04/23/07	05/06/07	04/29/07	05/18/07	18.50	334,124	6,181,294
05/07/07	05/20/07	05/13/07	06/01/07	18.50	336,230	6,220,255
05/21/07	06/03/07	05/27/07	06/15/07	18.50	353,260	6,535,310
06/04/07	06/17/07	06/10/07	06/29/07	18.50	337,679	6,247,062
06/18/07	07/01/07	06/24/07	07/13/07	18.50	341,521	6,318,139
07/02/07	07/15/07	07/08/07	07/27/07	18.50	345,752	6,396,412
07/16/07	07/29/07	07/22/07	08/10/07	18.50	333,438	6,168,603
07/30/07	08/12/07	08/05/07	08/24/07	18.50	347,811	6,434,504
08/13/07	08/26/07	08/19/07	09/07/07	18.50	337,253	6,239,181
08/27/07	09/09/07	09/02/07	09/21/07	18.50	335,121	6,199,739
09/10/07	09/23/07	09/16/07	10/05/07	18.50	331,445	6,131,733
09/24/07	10/07/07	09/30/07	10/19/07	18.50	352,580	6,522,730
10/08/07	10/21/07	10/14/07	11/02/07	18.50	355,828	6,582,818
10/22/07	11/04/07	10/28/07	11/16/07	18.50	355,294	6,572,939
11/05/07	11/18/07	11/11/07	11/30/07	18.50	375,779	6,951,912
11/19/07	12/02/07	11/25/07	12/14/07	18.50	395,601	7,318,619
12/03/07	12/16/07	12/09/07	12/28/07	18.50	351,392	6,500,752
				<u>31.74</u>	<u>\$ 9,890,374</u>	<u>\$ 313,903,428</u>
Combined Payroll Amounts				<u>45.91</u>	<u>\$ 30,257,307</u>	<u>\$ 1,389,106,313</u>

Notes:

1/ Exhibit VI, Item 18, page 12.

EQUITABLE GAS COMPANY

Calculation of Corporate Services Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	Lag Days	2/ Amount	Dollar Days
01/01/07	01/31/07	01/16/07	n/a	49.29	\$ 1,311,496	\$ 64,643,638
02/01/07	02/28/07	02/14/07	n/a	49.29	1,354,246	66,750,785
03/01/07	03/31/07	03/16/07	n/a	49.29	1,354,246	66,750,785
04/01/07	04/30/07	04/15/07	n/a	49.29	1,354,246	66,750,785
05/01/07	05/31/07	05/16/07	n/a	49.29	1,354,246	66,750,785
06/01/07	06/30/07	06/15/07	n/a	49.29	1,267,733	62,486,560
07/01/07	07/31/07	07/16/07	n/a	49.29	1,354,246	66,750,785
08/01/07	08/31/07	08/16/07	n/a	49.29	1,354,246	66,750,785
09/01/07	09/30/07	09/15/07	n/a	49.29	1,331,410	65,625,199
10/01/07	10/31/07	10/16/07	n/a	49.29	1,354,246	66,750,785
11/01/07	11/30/07	11/15/07	n/a	49.29	1,354,246	66,750,785
12/01/07	12/31/07	12/16/07	n/a	49.29	1,449,883	71,464,733
				<u>49.29</u>	<u>\$ 16,194,490</u>	<u>\$ 798,226,412</u>

Notes:

1/ Exhibit VI, Item 18, page 13.

2/ Revenue Lag presented on Exhibit VI, Item 18, page 2.

EQUITABLE GAS COMPANY

Calculation of Other O&M-Goods & Services Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u>	<u>Amount</u> 1/	<u>Dollar Days</u> 1/
Other O&M Totals		\$ 3,568,382	\$ 100,655,431
Other Goods & Services Totals		11,640,164	399,128,278
OSS - NCO Totals		2,794,637	151,981,995
OSS - Trafford Totals		1,741,825	79,604,796
OSS - HEATH Consultants Totals		1,192,201	44,544,821
C. Leon Sherman & Associates		498,255	20,827,565
Pittsburgh Mailing & ADS		848,033	24,098,883
Retiree Benefits		<u>3,446,372</u>	<u>92,426,848</u>
Other O&M Totals		<u>\$ 25,729,869</u>	<u>\$ 913,268,617</u>
Other O&M Lag Days	<u>35.49</u>		

Notes:

1/ Exhibit VI, Item 18, pages 14 - 18.

2/ Schedule LKM-6, Page 6.

EQUITABLE GAS COMPANY

Calculation of Other O&M-C. Leon Sherman Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/	Payroll Period End	1/	Mid Point of Service Period	1/	Payment Date	1/	Lag Days	1/	Amount	1/	Dollar Days
12/01/06		12/31/06		12/16/06		01/30/07		45.00		\$ 87,651		\$ 3,944,295
01/01/07		01/31/07		01/16/07		03/01/07		44.00		76,761		3,377,484
02/01/07		02/28/07		02/14/07		03/20/07		33.50		57,826		1,937,171
04/01/07		04/30/07		04/15/07		05/22/07		36.50		155,913		5,690,825
05/01/07		05/31/07		05/16/07		06/28/07		43.00		15,191		653,213
06/01/07		06/30/07		06/15/07		07/24/07 2/		38.50		7,479		287,942
07/01/07		07/31/07		07/16/07		08/28/07		43.00		24,015		1,032,645
09/01/07		09/30/07		09/15/07		10/04/07		18.50		9,285		171,773
09/01/07		09/30/07		09/15/07		11/13/07		58.50		24,893		1,456,241
10/01/07		10/31/07		10/16/07		12/13/07		58.00		39,241		2,275,978
								41.80		\$ 498,255		\$ 20,827,565

Notes:

1/ Exhibit VI, Item 18, pages 15 - 18.

2/ Response to OTS-RE-23-D.

EQUITABLE GAS COMPANY

Calculation of Pensions & Benefits Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u> 1/	<u>Amount</u> 1/	<u>Dollar Days</u>
Total 401(k) Match & Retirement Contribution		\$ 1,944,377 2/	\$ 32,082,219
Total 401(k) Administration Fees		1,398	127,849
Total ESPP Discount		26,607	557,948
Total ESPP Administration Fees		15,813	1,821,280
Total HSA Company Contribution		162,250	(28,356,500)
Total HSA Account Fees		8,232	72,322
Total Health Claims, Admin & Enrollment Fees		2,736,530	24,628,772
Total Active Vision		61,489	2,435,075
Total Executive Health Care Exams		9,225 3/	-
Total Active Life, AD&D, LTD		182,935	7,197,330
Total Active Dental		242,987	7,766,042
Total Employee Assistance Program		14,770	140,129
Total Aon Admin Fees		148,394	13,680,486
Retirees Pensions & Benefits Totals		3,446,372	92,426,848
Pension & Benefit Totals		<u>\$ 9,001,379</u>	<u>\$ 154,579,800</u>
Pension & Benefits Lag Days	<u>17.17</u>		

Notes:

- 1/ Exhibit VI, Item 18, pages 20 - 27.
2/ Schedule LKM-6, page 8.
3/ Schedule LKM-6, Page 9.

EQUITABLE GAS COMPANY

Calculation of 401(k) Match & Retirement Contribution Lag
For the Test Year Ended December 31, 2008

	<u>Payroll Period Begin</u>	<u>Payroll Period End</u>	<u>Mid Point of Service Period</u>	<u>Payment Date</u>	<u>Lag Days</u>	<u>Amount</u>	<u>Dollar Days</u>
<u>401(k) Match & Retirement Contribution</u>							
Total Per Company						\$ 1,945,742 1/	\$ 32,104,741 1/
Bonus Contribution per Co.	01/14/07 1/	01/27/07 1/	01/20/07 1/	02/06/07 1/	16.50 1/	(1,365) 1/	(22,523) 1/
Bonus Contribution per OCA	01/01/06	12/31/06	07/02/06	02/06/07	219.00 2/	-	-
Total 401(k) Match & Retirement Contribution Per OCA					16.50	<u>1,944,377</u>	<u>32,082,219</u>

Notes:

1/ Exhibit VI, Item 18, page

2/ Based on the response to OTS-RE-18-D.

EQUITABLE GAS COMPANY

Calculation of Executive Health Care Exams Lag
For the Test Year Ended December 31, 2008

<u>Payroll Period Begin</u>	<u>Payroll Period End</u>	<u>Mid Point of Service Period</u>	<u>Payment Date</u> ^{1/}	<u>Lag Days</u>	<u>Amount</u> ^{1/}	<u>Dollar Days</u>
<u>Executive Health Exams</u>						
01/04/07 2/	01/04/07 2/	01/04/07	01/04/07	0.00	\$ 1,825	\$ -
03/06/07 2/	03/06/07 2/	03/06/07	03/06/07	0.00	3,650	-
03/15/07 2/	03/15/07 2/	03/15/07	03/15/07	0.00	1,825	-
08/02/07 2/	08/02/07 2/	08/02/07	08/02/07	0.00	1,925	-
Totals				<u>0.00</u>	<u>\$ 9,225</u>	<u>\$ -</u>

Notes:

1/ Exhibit VI, Item 18, page 23.

2/ Response to OCA I-50.

EQUITABLE GAS COMPANY

Calculation of Taxes Other Than Income Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u>	<u>Amount</u>	<u>Dollar Days</u>
Combined Taxes Other Than Income Amounts Per Company		\$ 1,394,466 2/	\$ (92,099,751) 2/
Payroll Taxes	- 1/	- 3/	- 4/
Combined Taxes Other Than Income Amounts	<u>(66.05)</u>	<u>\$ 1,394,466</u>	<u>\$ (92,099,751)</u>

Notes:

1/ Exhibit VI, Item 18, page 12.

2/ Exhibit VI, Item 18, page 31.

3/ Exhibit III, Item § 53.53 III.A.17, Sheet 6.

4/ Lag days x Amount.

EQUITABLE GAS COMPANY

Adjustment to Annualize Operating Revenues
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Annualize Operating Revenues	<u>\$ 22,790,905</u> 1/
Adjustment to Operating Revenues	<u><u>\$ 22,790,905</u></u>

Notes:

1/ Adjustment Recommended by OCA Witness Glen Watkins.

EQUITABLE GAS COMPANY

Adjustment to Reverse Company's Adjustment to Include
Collection Costs in O&M Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Collection Costs Included in the Cost of Service	<u>612,202</u> 1/
Adjustment to O&M Expenses	<u><u>\$ (612,202)</u></u>

Notes:

1/ Exhibit III, Item § 53.53 III.A.17, Page 9.

EQUITABLE GAS COMPANY

**Adjustment to Remove Excess Anode Expenses
For the Test Year Ended December 31, 2008**

	<u>Amount</u>
Excess Anode Expenses	<u>\$ 269,658 1/</u>
Adjustment to O&M Expenses	<u><u>\$ (269,658)</u></u>

Notes:

1/ Response to OCA I-19.

EQUITABLE GAS COMPANY

**Adjustment to Normalize Customer Experience Study Costs
For the Test Year Ended December 31, 2008**

	<u>Amount</u>
Customer Experience Study Costs	\$ 795,858 1/
Normalization Period (Years)	<u>5</u>
Normalized Customer Experience Study Costs	\$ 159,172
Customer Experience Study Costs per Company	<u>795,858</u>
Adjustment to O&M Expenses	<u><u>\$ (636,686)</u></u>

Notes:

1/ Response to OCA I-26.

EQUITABLE GAS COMPANY

Adjustment to Annualize PA One Call Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Routine Unit Cost	\$ 16.05 1/
Number of Units	<u>32,420 2/</u>
Annual Costs at Contract Rate	\$ 520,341 1/
Increased PA One Call System Charge	<u>20,974 2/</u>
Annulized PA One Call Expense	\$ 541,315
Annulized PA One Call Expense per Company	<u>572,183</u>
Adjustment to O&M Expenses	<u><u>\$ (30,868)</u></u>

Notes:

1/ Response to OCA I-20.

2/ Schedule JCM-6.

EQUITABLE GAS COMPANY

Adjustment to Remove Lobbying Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Lobbying Expenses Included in Corporate Allocation	\$ - 1/
Portion of AGA Dues Attributed to Lobbying	<u>(1,584) 2/</u>
Adjustment to O&M Expenses	<u><u>\$ (1,584)</u></u>

Notes:

1/ Lobbying Expense per Response to OTS-RE-78-D less \$88,378 per Page 13,
Line 15 of Witness Mitchell Rebuttal Testimony.

2/ Exhibit VI, Standard Data Request, Volume 1, Item No.33.

EQUITABLE GAS COMPANY

Adjustment to Annualize Payroll Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
<u>Payroll Expenses</u>	
<u>Unfilled Positions</u>	
Compression Operator	\$ -
Compression Operator	-
Producer Services Analyst	39,967 1/
Producer Services Engineer	65,000 1/
<u>Vacated Positions</u>	
Position # 99909180	-
Adjustment to Payroll Expenses	<u>\$ (104,967)</u>
<u>Fringe Benefits Expenses</u>	
Total Fringe Benefits Percentage	29.97%
Total Decrease in Fringe Benefits Expenses	<u>\$ (31,459)</u>
Adjustment to O&M Expenses	<u><u>\$ (136,426)</u></u>

Notes:

1/ Response to OCA I-11.

EQUITABLE GAS COMPANY

Adjustment to Reflect Pension & Postretirement Benefits at the Ongoing Level
For the Test Year Ended December 31, 2008

	<u>Amount</u>
2008 Total Pension Cost	\$ 594,491 1/
2008 Total Postretirement Benefits Cost	<u>1,807,247 1/</u>
Total Pension & Postretirement Benefits Costs	\$ 2,401,738
Pennsylvania Percentage	<u>98.36% 2/</u>
Pennsylvania Pension & Postretirement Benefits Costs	\$ 2,362,349
O&M Percentage	<u>84.40%</u>
Pennsylvania Pension & Postretirement Benefits Expense	\$ 1,993,823 3/
PA Pension & Postretirement Benefits Expense per Company	<u>2,457,296 4/</u>
Adjustment to O&M Expenses	<u><u>\$ (463,473)</u></u>

Notes:

1/ Response to OTS-RE-68-D.

2/ Standard Data Requests, Item 23.

3/ Standard Data Requests, Item 19.

4/ Response to OTS-RE-139-D.

EQUITABLE GAS COMPANY

**Adjustment to Normalize Regulatory Commission Expenses
For the Test Year Ended December 31, 2008**

	<u>Amount</u>
Cost of the Current Rate Case	\$ 1,051,160 1/
Cost of the Service Life Study	<u>15,000 2/</u>
Total Rate Case	\$ 1,066,160
Normalization Period (Years)	<u>5</u>
Normalized Rate Case Expenses	\$ 213,232
Historical Test Year Regulatory Expenses	13,474 3/
Costs Related to West Virginia Matters	<u>(8,626) 4/</u>
Future Test Year Regulatory Expenses per OCA	\$ 218,080
Future Test Year Regulatory Expenses per Company	<u>516,861</u>
Adjustment to O&M Expenses	<u><u>\$ (298,781)</u></u>

Notes:

1/ Exhibit III, Item § 53.53 III.A.20 Sheet 2.

2/ Per OTS-RE-89-D, the total cost of the management audit and the service life study is \$765,000, and OCA IV-15 the management audit cost is \$750,000.

3/ Exhibit III, Item § 53.53 III.A.28 Sheet 7.

4/ Per response to OCA IV-8.

EQUITABLE GAS COMPANY

Adjustment to Annualize the Increase in Cost of Fuel
For the Test Year Ended December 31, 2008

	<u>Diesel Gallons</u>		<u>Gasoline Gallons</u>		<u>Totals</u>
January 2008 - August 2008 Fuel Usage	57,247	1/	178,709	1/	
Period Number of Months	8		8		
Annual Number of Months	<u>12</u>		<u>12</u>		
Annualized 2008 Fuel Usage	85,871		268,064		
2008 Price per Gallon	<u>\$ 4.00</u>	2/	<u>\$ 3.61</u>	2/	
Annualized Fuel Expense	\$ 343,482		\$ 967,709		\$ 1,311,191
Annualized Fuel Expense per Company	<u>392,391</u>	2/	<u>988,423</u>	2/	<u>1,380,814</u>
Adjustment to O&M Expenses	<u>\$ (48,909)</u>		<u>\$ (20,714)</u>		<u>\$ (69,623)</u>

Notes:

1/ Response to OCA VIII-18.

2/ Response to OCA I-17.

EQUITABLE GAS COMPANY

Adjustment to Normalize Injuries & Damages Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>	<u>Totals</u>
<u>Charges Against the Reserve (Claims)</u>		
2005 Charges Against the Reserve	\$ 235,769 1/	
2006 Charges Against the Reserve	256,243 1/	
2007 Charges Against the Reserve	<u>363,135 1/</u>	
Average		\$ 285,049
<u>Legal Settlements</u>		
2005 Settlement Expense	\$ 108,750 1/	
2006 Settlement Expense	311,680 1/	
2007 Settlement Expense	<u>3,960,828 1/</u>	
Average		\$ 1,460,419
<u>Test Year Expense</u>		
2007 Expense Accrual	\$ 2,888,475 1/	
2007 Reserve Adjustments	(2,992,765) 1/	
Company's Pro Forma Normalization Adjustment	<u>3,145,292 1/</u>	
Net Injuries & Damages Expense		<u>3,041,002</u>
Adjustment to O&M Expenses		<u><u>\$(1,295,534)</u></u>

Notes:

1/ Response to OCA I-1.

EQUITABLE GAS COMPANY

Adjustment to Normalize Right of Way Mowing Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>	
Revised Right of Way Mowing Expense	\$ 200,100	1/
Right of Way Mowing Expense	<u>539,910</u>	1/
Adjustment to O&M Expenses	<u><u>\$ (339,810)</u></u>	

Notes:

1/ Witness Mitchell Rebuttal Testimony at Page 27, Lines 6 through 12.

EQUITABLE GAS COMPANY

Adjustment to Reverse Cathodic Protection Costs Related to DOT Compliance
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Cathodic Protection Costs	<u>\$ 133,524 1/</u>
Adjustment to O&M Expenses	<u><u>\$ (133,524)</u></u>

Notes:

1/ Response to OCA I-4.

EQUITABLE GAS COMPANY

Adjustment to Reflect OCA's Universal Service Costs adjustments
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Total Universal Service Adjustments per OCA	
Witness Colton	\$ 11,170,763 1/
CAP Administrative Costs	<u>168,794 1/</u>
Total Universal Service and Administrative Costs per OCA	\$ 11,339,557
Total Universal Service and Administrative Costs per Company	<u>16,874,692 2/</u>
Adjustment to O&M Expenses	<u><u>\$ (5,535,135)</u></u>

Notes:

1/ Schedule RDC-2SR.

2/ Schedule RDC-5.

EQUITABLE GAS COMPANY

Interest Synchronization Adjustment
For the Test Year Ended December 31, 2008

	<u>Amount</u>
OCA Rate Base	\$ 577,339,819 1/
Weighted Cost of Debt	<u>3.08%</u>
Adjusted Interest Deduction	\$ 17,782,066
Interest Deduction Per Company	<u>16,972,820 2/</u>
Adjustment to Synchronize Interest Expense	\$ 809,246
Effective State Income Tax Rate	<u>9.99%</u>
Adjustment to State Income Taxes	<u>\$ (80,844)</u>
Federal Income Tax Base	\$728,402
Federal Income Tax Rate	<u>35.00%</u>
Adjustment to Federal Income Taxes	<u>\$ (254,941)</u>

Notes:

1/ Schedule LKM-2, Page 1.

2/ Exhibit III, Item § 53.53 III.A.17, Sheet 8.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08

NB6, PA

R45

Pennsylvania Public Utility Commission,

v.

Equitable Gas Company

Docket No. R-2008-2029325, et al

Independent Oil and Gas Association of
Pennsylvania

v.

Equitable Gas Company

C-20066800

DIRECT TESTIMONY OF

DAVID C. PARCELL

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

RATE OF RETURN

OCTOBER 8, 2008

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1 I. INTRODUCTION

2 Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

3 A. My name is David C. Parcell. I am President and Senior Economist of Technical
4 Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond,
5 Virginia 23219.

6 Q. PLEASE BRIEFLY DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

7 A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic
8 Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia
9 Commonwealth University. I have been a consulting economist with Technical
10 Associates since 1970. In connection with this, I have previously filed cost of capital
11 testimony in more than 400 public utility ratemaking proceedings before some 40
12 regulatory agencies in the United States and Canada. Attachment I provides a more
13 complete description of my education and relevant work experience.

14 **O. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

15 A. I have been retained by the Office of Consumer Advocate (“OCA”) to evaluate the cost
16 of capital aspects of the current filing of Equitable Gas Company (“Equitable Gas” or
17 “Company”). I have performed independent studies and am making recommendations of
18 the current cost of capital for Equitable Gas. In addition, since Equitable Gas is a
19 subsidiary of Equitable Resources (“Equitable Resources” or “Parent”), I have also
20 evaluated this entity in my analyses.

1 **Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?**

2 A. Yes, I have prepared one exhibit, labeled Exhibit DCP-1, identified as Schedule 1
3 through Schedule 14. This exhibit was prepared either by me or under my direction. The
4 information contained in this exhibit is correct to the best of my knowledge and belief.

5

1 **II. RECOMMENDATIONS AND SUMMARY**

2 **Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?**

3 A. My overall cost of capital recommendation for Equitable Gas is shown on Schedule 1 and
4 can be summarized as follows:

5

	<u>Percent</u>	<u>Cost</u>	<u>Return</u>
6 Long-Term Debt	43.35%	6.39%	2.77%
7 Short-Term Debt	9.65%	3.26%	0.31%
8 Common Equity	47.00%	9.30%	4.37%
9 Total	100.00%		7.45%

10 **Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.**

11 A. This proceeding is concerned with Equitable Gas' regulated natural gas utility operations
12 in Pennsylvania. My analyses are concerned with the Company's total cost of capital.
13 The first step in performing these analyses is the development of the appropriate capital
14 structure. Equitable Gas, as a division of Equitable Resources, does not have its own
15 distinct capital structure. The Company proposes to use a hypothetical capital structure.
16 I have used a modification of the Company's hypothetical capital structure, including
17 short-term debt, in my analyses. Instead of a hypothetical 50 percent common equity
18 ratio, as proposed by the Company, I propose a hypothetical 47 percent common equity
19 ratio.

20 The second step in a cost of capital calculation is a determination of the embedded
21 cost rates of debt. I have used the cost rates for long-term debt and short-term debt
22 proposed by the Company.

23 The third step in the cost of capital calculation is the estimation of the cost of
24 common equity. I have employed three recognized methodologies to estimate the cost of

1 equity for Equitable Gas. Each of these methodologies is applied to a group of proxy
2 natural gas utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.0-9.3%
Capital Asset Pricing Model	9.4%
Comparable Earnings	9.0-10.0%

3
4
5
6
7 Based upon these findings, it is my conclusion that the cost of common equity for
8 Equitable Gas is within a range of 9.0 percent to 10.0 percent which is based upon the
9 range for each model examined. This Commission has traditionally primarily relied on
10 the DCF methodology. I recommend a 9.30 percent as the cost of equity for Equitable
11 Gas, which gives more weight to the DCF results and approximates the CAPM results.

12 Combining these three steps into weighted cost of capital results in an overall rate
13 of return of 7.45 percent (which incorporates a cost of common equity of 9.30 percent).
14

1 **III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES**

2 **Q. WHAT ARE THE PRIMARY ECONOMIC AND LEGAL PRINCIPLES THAT**
3 **ESTABLISH THE STANDARDS FOR DETERMINING A FAIR RATE OF**
4 **RETURN FOR A REGULATED UTILITY?**

5
6 A. Public utility rates are normally established in a manner designed to allow the recovery of
7 their costs, including capital costs. This is frequently referred to as “cost of service”
8 ratemaking. Rates for regulated public utilities traditionally have been primarily
9 established using the “rate base - rate of return” concept. Under this method, utilities are
10 allowed to recover a level of operating expenses, taxes, and depreciation deemed
11 reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of
12 return on the assets utilized (i.e. rate base) in providing service to their customers.

13 The rate base is derived from the asset side of the utility’s balance sheet as a
14 dollar amount and the rate of return is developed from the liabilities/owners’ equity side
15 of the balance sheet as a percentage. Thus, revenue impact of the cost of capital is
16 derived by multiplying the rate base by the rate of return, including income taxes.

17 The rate of return is developed from the cost of capital, which is estimated by
18 weighting the capital structure components (i.e. debt, preferred stock, and common
19 equity) by their percentages in the capital structure and multiplying these values by their
20 cost rates. This is also known as the weighted cost of capital.

21 Technically, “fair rate of return” is a legal and accounting concept that refers to an
22 ex post (after the fact) earned return on an asset base, while the cost of capital is an
23 economic and financial concept which refers to an ex ante (before the fact) expected or
24 required return on a liability base. In regulatory proceedings, however, the two terms are

1 more often used interchangeably than not, and I have equated the two concepts in my
2 testimony.

3 From an economic standpoint, a fair rate of return is normally interpreted to mean
4 that an efficient and economically managed utility will be able to maintain its financial
5 integrity, attract capital, and establish comparable returns for similar risk investments.
6 These concepts are derived from economic and financial theory and are generally
7 implemented using financial models and economic concepts.

8 Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on
9 my understanding that United States Supreme Court decisions provide the controlling
10 standards for a fair rate of return. The first decision is Bluefield Water Works and
11 Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this
12 decision, the Court stated:

13 What annual rate will constitute just compensation depends upon many
14 circumstances and must be determined by the exercise of fair and
15 enlightened judgment, having regard to all relevant facts. A public utility
16 is entitled to such rates as will permit it to earn a return on the value of the
17 property which it employs for the convenience of the public equal to that
18 generally being made at the same time and in the same general part of the
19 country on investments in other business undertakings which are attended
20 by corresponding risks and uncertainties; but it has no constitutional right
21 to profits such as are realized or anticipated in highly profitable enterprises
22 or speculative ventures. The return should be reasonably sufficient to
23 assure confidence in the financial soundness of the utility, and should be
24 adequate, under efficient and economical management, to maintain and
25 support its credit and enable it to raise the money necessary for the proper
26 discharge of its public duties. A rate of return may be reasonable at one
27 time, and become too high or too low by changes affecting opportunities
28 for investment, the money market, and business conditions generally.

29
30 It is generally understood that the Bluefield decision established the following standards
31 for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It

1 also noted that required returns change over time, and there is an underlying assumption
2 that the utility be operated in an efficient manner.

3 The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320
4 U.S. 591 (1942). In that decision, the Court stated:

5 The rate-making process under the [Natural Gas] Act, i.e., the fixing of
6 'just and reasonable' rates, involves a balancing of the investor and
7 consumer interests From the investor or company point of view it is
8 important that there be enough revenue not only for operating expenses
9 but also for the capital costs of the business. These include service on the
10 debt and dividends on the stock. By that standard the return to the equity
11 owner should be commensurate with returns on investments in other
12 enterprises having corresponding risks. That return, moreover, should be
13 sufficient to assure confidence in the financial integrity of the enterprise,
14 so as to maintain its credit and to attract capital.

15
16 The three economic and financial parameters in the Bluefield and Hope decisions
17 - comparable earnings, financial integrity, and capital attraction - reflect the economic
18 criteria encompassed in the "opportunity cost" principle of economics. The opportunity
19 cost principle provides that a utility and its investors should be afforded an opportunity
20 (not a guarantee) to earn a return commensurate with returns they could expect to achieve
21 on investments of similar risk. The opportunity cost principle is consistent with the
22 fundamental premise, on which regulation rests, namely, that it is intended to act as a
23 surrogate for competition.

24 **Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST**
25 **OF CAPITAL FOR A UTILITY?**

26
27 A. Neither the courts nor economic/financial theory have developed exact and mechanical
28 procedures for precisely determining the cost of capital. This is the case because the cost
29 of capital is an opportunity cost and is prospective-looking, which dictates that it must be
30 estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the discounted cash flow (“DCF”), capital asset pricing model (“CAPM”), comparable earnings (“CE”) and risk premium (“RP”) methods. This Commission consistently uses the DCF model as the preferred methodology.

Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE COST OF COMMON EQUITY IN THIS PROCEEDING?

A. I have utilized three methodologies to determine Equitable Gas' cost of common equity: the DCF, CAPM, and CE methods. I note that I am primarily relying on the DCF methodology, as is this Commission's practice, and am using the CAPM and CE methodologies as a check. I have not employed a RP model in my analyses although, as discussed later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

1 **IV. GENERAL ECONOMIC CONDITIONS**

2 **Q. WHY ARE ECONOMIC AND FINANCIAL CONDITIONS IMPORTANT IN**
3 **DETERMINING THE COSTS OF CAPITAL?**

4
5 A. The costs of capital, for both fixed-cost (debt and preferred stock) components and
6 common equity, are determined in part by current and prospective economic and
7 financial conditions. At any given time, each of the following factors has an influence on
8 the costs of capital: the level of economic activity (*i.e.*, growth rate of the economy), the
9 stage of the business cycle (*i.e.*, recession, expansion, or transition), and the level of
10 inflation, and expected economic conditions. My understanding is that this position is
11 consistent with the Supreme Court Bluefield decision that noted “[a] rate of return may
12 be reasonable at one time, and become too high or too low by changes affecting
13 opportunities for investment, the money market, and business conditions generally.”

14 **Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE**
15 **YOU EVALUATED IN YOUR ANALYSES?**

16
17 A. I have examined several sets of economic statistics from 1975 to the present. I chose this
18 time period because it permits the evaluation of economic conditions over three full
19 business cycles plus the current cycle to date, allowing for an assessment of changes in
20 long-term trends. This period also approximates the beginning and continuation of active
21 rate case activities by public utilities.

22 A business cycle is commonly defined as a complete period of expansion
23 (recovery and growth) and contraction (recession). A full business cycle is a useful and
24 convenient period over which to measure levels and trends in long-term capital costs
25 because it incorporates the cyclical (*i.e.*, stage of business cycle) influences, and thus,
26 permits a comparison of structural (or long-term) trends.

1 **Q. PLEASE DESCRIBE THE TIMEFRAME OF THE THREE PRIOR BUSINESS**
2 **CYCLES AND THE MOST RECENT CYCLE.**

3
4 A. The three prior complete cycles and most recent cycle cover the following periods:

5
6

<u>Business Cycle</u>	<u>Expansion Cycle</u>	<u>Contraction Period</u>
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Present (?)*	

7
8

9 * The (?) in the expansion cycle of the current cycle means we do not know if we
10 are currently in a recession.
11

12 **Q. DO YOU HAVE ANY GENERAL OBSERVATIONS CONCERNING THE**
13 **RECENT TRENDS IN ECONOMIC CONDITIONS AND THEIR IMPACT ON**
14 **CAPITAL COSTS OVER THIS BROAD PERIOD?**

15
16 A. Yes, I do. As I will describe below, the U.S. economy has enjoyed general prosperity
17 and stability over the period since the early 1980s. This period has been characterized by
18 longer economic expansions, relatively tame contractions, relatively low and declining
19 inflation, and declining interest rates and other capital costs. The current business cycle
20 began in late 2001, following a somewhat modest recession earlier in the year.

21 Over the past year, on the other hand, the economy has slowed significantly,
22 initially as a result of the 2007 collapse of the "sub-prime" mortgage market and related
23 liquidity crises in the financial sector of the economy. More recently, this financial crisis
24 has intensified with a more broad-based decline based on an intensive increase in
25 petroleum prices and an increasing decline in the U.S. financial sector culminating with
26 the collapse and/or bailouts of a substantial number of long-standing institutions such as
27 Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae and AIG. This
28 crisis has recently been described as the worst financial crisis since the Great Depression.
29 The U.S. government has recently taken unprecedented actions to attempt to correct or

1 minimize this crisis. As of this time the effects of these potential actions are unclear.
2 There is, as a result, some concern that the economy may incur or already be in a
3 recession. Should the economy incur a recession, the impacts on cost of capital would
4 likely be characterized by lower utility growth and declining capital costs due to a decline
5 in corporate profits and expected earnings growth.

6 **Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL**
7 **CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.**

8
9 A. Schedule 2 shows several sets of economic data. Pages 1 and 2 contain general
10 macroeconomic statistics while Pages 4 through 6 contain financial market statistics.
11 Pages 1 and 2 of Schedule 2 show that the U.S. economy entered 2008 as the sixth year
12 of an economic expansion although, as indicated previously, the economy is currently in
13 decline. This is indicated by the growth in real (*i.e.*, adjusted for inflation) Gross
14 Domestic Product, industrial production, and the unemployment rate. This recent
15 expansion was characterized as slower growth, in comparison to prior expansions. This
16 resulted in lower inflationary pressures and interest rates.

17 The rate of inflation is also shown on Pages 1 and 2 of Schedule 2. As is reflected
18 in the Consumer Price Index (CPI), for example, inflation rose significantly during the
19 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of
20 inflation declined substantially in 1981 and remained at or below 6.1 percent during the
21 1983-1991 business cycle. Since 1991, the CPI has been 4.1 percent or lower. The 4.1
22 percent rate of inflation in 2007 was slightly above the levels since 2000, but is well
23 below the levels of the past thirty years. Inflation has increased in 2008, largely as a
24 result of a significant increase in petroleum costs.

1 **Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?**

2 A. Pages 3 and 4 of Schedule 2 show several series of interest rates. Rates rose sharply to
3 record levels in 1975-1981 when the inflation rate was high and generally rising. Interest
4 rates declined substantially in conjunction with inflation rates throughout the remainder
5 of the 1980s throughout the 1990s. Interest rates declined even further from 2000-2005
6 and generally recorded their lowest levels since the 1960s.

7 During the past several years, long-term interest rates have remained low by
8 historic standards. During the 2001 recession and early in the succeeding expansion, the
9 Federal Reserve lowered interest rates (*i.e.*, Federal Funds rate) 11 times in 2001 and
10 twice in 2003 in an effort to stimulate the economy. Following this, the Federal Reserve
11 increased short-term interest rates on 17 occasions between 2004 and 2006, although
12 each time by only 0.25 percent, in an attempt to ensure that any perceived inflationary
13 expectations will not stifle continued economic growth. Nevertheless, the Federal
14 Reserve actions did not result in a pronounced increase in long-term rates. Most recently,
15 however, the Federal Reserve has lowered the Federal Funds rate (*i.e.*, short-term rate) on
16 six occasions. Over the past few years, long-term interest rates have remained relatively
17 stable, by historic standards. The first several months of 2008 have experienced a decline
18 in short-term rates, relatively little change in U.S. Treasury Securities, and an increase in
19 corporate bond yields.

20 **Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES?**

21 A. Pages 5 and 6 of Schedule 2 show several series of common stock prices and ratios.
22 These indicate that share prices were essentially stagnant during the high
23 inflation/interest rate environment of the late 1970s and early 1980s. On the other hand,

1 the 1983-1991 business cycle and the most recent cycles witnessed a significant upward
2 trend in stock prices. Since the beginning of the current financial crisis, on the other
3 hand, stock prices have declined precipitously and have been very volatile. Stock prices
4 in 208 are down significantly from 2007 levels, reflecting the financial/economic crises.

5 **Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF**
6 **ECONOMIC AND FINANCIAL CONDITIONS?**

7
8 A. It is apparent that capital costs remain low in comparison to the levels that have prevailed
9 over the past three decades in spite of the current financial crisis. In addition, the current
10 weakness in the economy has resulted in a decline in capital costs. Therefore, it can
11 reasonably be expected that cost of equity models currently indicate returns that are lower
12 than returns experienced in prior years. As noted elsewhere in my testimony, this is a
13 factor that should be considered in establishing the current cost of equity for Equitable
14 Gas.

V. EQUITABLE GAS' OPERATIONS AND RISKS

2 **O. PLEASE SUMMARIZE EQUITABLE GAS AND ITS OPERATIONS.**

3 A. Equitable Gas is a regulated public utility that provides natural gas distribution services
4 to approximately 275,000 customers in Southwestern Pennsylvania. Until recently,
5 Equitable Gas was a division of Equitable Resources. However, the recent reorganization
6 of Equitable Resources into a holding Company results in Equitable Gas becoming a
7 distinct subsidiary.

8 Q. PLEASE DESCRIBE EQUITABLE RESOURCES.

9 A. Equitable Resources is an “integrated energy company, with an emphasis on Appalachian
10 area natural gas activities, including production, gathering and processing, and
11 distribution, transmission, storage and marketing” (Source: 2007 Form 10-K). Equitable
12 Resources currently operates through two business segments: (1) Equitable Supply -
13 production and gathering of natural gas; and, (2) Equitable Utilities - distribution of
14 natural gas.

Schedule 3 shows the segment operations of Equitable Resources over the past three years. The Equitable Utilities segment percentages have been as follows:

17				Operating	
18		<u>Year</u>	<u>Revenues</u>	<u>Income</u>	<u>Assets</u>
19		2005	67.5%	28.6%	N/A
20		2006	66.5%	33.6%	42.9%
		2007	67.3%	36.4%	35.9%

22 This indicates that the Equitable Utilities segment of Equitable Resource does not
23 account for the major portion of the Company's operations (in terms of operating income
24 and assets).

1 **Q. HOW IS EQUITABLE GAS FINANCED?**

2 A. As a division of Equitable Resources, Equitable Gas did not secure its own equity and
3 debt financing, but obtained all of its capital from Equitable Resources. As a result of the
4 reorganization, Equitable Gas is now a subsidiary and will raise its own debt capital, but
5 continue to receive equity from its parent.

6 **Q. WHAT ARE THE CURRENT BOND RATINGS OF EQUITABLE RESOURCES?**

7 A. Equitable Resources' debt is rated Baa1 by Moody's and BBB by Standard & Poor's.
8 Schedule 4 reflects the trend in Equitable Resources' ratings in recent years. This
9 indicates a downward trend in its ratings.

10 **Q. WHAT HAVE RECENT RATING AGENCY REPORTS STATED ABOUT**
11 **EQUITABLE RESOURCES AND ITS RATINGS?**

12
13 A. A recent (March 25, 2008) Standard & Poor's RatingsDirect report on Equitable
14 Resources made the following statements:

15 Rationale

16 On March 25, 2008, Standard & Poor's Ratings Services assigned its
17 'BBB' rating to Equitable Resources Inc.'s (EQT) \$500 million senior
18 unsecured notes due 2018. In addition, Standard & Poor's also affirmed
19 the ratings on the company, including the 'BBB' corporate credit rating.
20 The outlook remains negative.

21
22 EQT has been rapidly expanding its gas exploration and production (E&P)
23 and gas-gathering activities in its Appalachian region and plans to finance
24 this expansion mostly with debt.

25 ...

26 Standard & Poor's views E&P as a fundamentally much riskier activity
27 than Equitable's gas distribution operation, and Equitable's focus on its
28 E&P business has grown significantly, which has increased the company's
29 overall business risk.

30
31 EQT division Equitable Gas Co. is a small natural gas local distribution
32 company that serves about 275,000 customers in the Pittsburgh area.
33 Equitable Gas' regulated revenues provide some stabilization on EQT's
34 overall financial position, but with minimal free cash flow, its contribution
35 is limited.

1 Moody's made similar statements about Equitable Resources in an October 31,
2 2007 Credit Opinion:

3
4 Equitable Resources, Inc. (Equitable, Baal sr. uns.) is a vertically
5 integrated company engaged in the production and delivery of natural gas
6 in the Appalachian Basin. The production segment (E&P) accounted for
7 approximately 57% of consolidated operating income in the LTM 9/07;
8 gathering accounted for 9%; regulated interstate natural gas pipeline and
9 storage, 7%; regulated gas distribution (LDC), 9%; and marketing, 18%.

10
11
12 Rating Rationale

13 Equitable's Baal rating reflects an increased tolerance for business and
14 financial risk as the company adopts a more growth-oriented strategy than
15 in the recent past. The utility segment is a stabilizing, though minor factor
16 in its credit profile. E&P and gathering makes Equitable more sensitive to
17 gas prices and volumes than many diversified gas companies which are
18 more regulated and larger.

19
20 These reports make it clear that Equitable Resources' ratings are largely based on its
21 diversified, and largely unregulated, operations.

22 **Q. HOW HAS THE RECENT REORGANIZATION OF EQUITABLE RESOURCES,**
23 **AND THE CREATION OF EQUITABLE GAS AS A SUBSIDIARY, IMPACTED**
24 **THE RISKS OF THE UTILITY?**

25
26 A. Equitable Resources recently reorganized by forming a holding company in which
27 several of its former divisions became subsidiaries. One notable aspect of this
28 reorganization is the creation of Equitable Gas as a subsidiary of Equitable Resources.

29 One notable impact of this reorganization, and related establishment of Equitable
30 Gas as a subsidiary, is a reduction of risk for the utility. In the reorganization docket
31 (Docket No. A-121100F006), Equitable Resources made the following statement in its
32 "Statement in Support" of the proposed reorganization:

33 The Company's proposed reorganization will separate its Pennsylvania
34 regulated utility operations from its riskier non-regulated natural gas
35 production and other non-regulated activities. The Commission supports

1 the legal separation of a utility and its parent and "ring-fencing" that
2 insulated the utility from the financial effects of its parent.

3
4 In addition, Equitable Resources' January 8, 2007 Application in this docket made the
5 following statement:

6 The Company considers it to be in the best interest of customers and
7 shareholders to change the corporate structure of Equitable Resources
8 through its Reorganization. The Company also believes that following the
9 Reorganization it may be able to finance its natural gas utility businesses
10 at a cost of capital that is at least the same as, and may be less than, the
11 cost of capital for the entire organization. The reason for this is the nature
12 of the regulated business and the fact that it will no longer be a division of
13 the parent company. The parent company will continue to own non-
14 regulated businesses. The Company further believes that the
15 Reorganization will reduce the utility's risk profile through the
16 segregation of the utility assets in a separate legal entity structure.

17
18 This is consistent with the statements made by Moody's and Standard & Poor's
19 cited above that indicated that the regulated gas utility operations of Equitable Gas are
20 less risky than the non-regulated operations of Equitable Resources.

21 It is apparent that the impact of the reorganization and the creation of Equitable
22 Gas as a subsidiary have the impact of reducing the utility's risks. This is a factor that
23 should be considered in establishing its cost of equity.

1 **VI. CAPITAL STRUCTURE AND COST OF DEBT**

2 **Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL**
3 **STRUCTURE IN A REGULATORY FRAMEWORK?**

4
5 A. A utility's capital structure is important since the concept of rate base - rate of return
6 regulation requires that a utility's capital structure be determined and utilized in
7 estimating the total cost of capital. Within this framework, it is proper to ascertain
8 whether the utility's capital structure is appropriate relative to its level of business risk
9 and relative to other utilities.

10 As discussed in Section III of my testimony, the purpose of determining the
11 proper capital structure for a utility is to help ascertain the capital costs of the company.
12 The rate base - rate of return concept recognizes the assets which are employed in
13 providing utility services and provides for a return on these assets by identifying the
14 liabilities and common equity (and their cost rates) which are used to finance the assets.
15 In this process, the rate base is derived from the asset side of the balance sheet and the
16 cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The
17 inherent assumption in this procedure is that the dollar values of the capital structure and
18 the rate base are approximately equal and the former is utilized to finance the latter.
19 The common equity ratio (i.e. the percentage of common equity in the capital structure) is
20 the capital structure item which normally receives the most attention. This is the case
21 since common equity: (1) usually commands the highest cost rate; (2) generates
22 associated income tax liabilities; and (3) causes the most controversy since its cost cannot
23 be precisely determined.

1 Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURE OF
2 EQUITABLE RESOURCES?
3

4 A. I have first examined the five year historic (2002-2006) capital structure ratios of
5 Equitable Resources. The Company's capital structure ratios are shown on Schedule 5.
6 The common equity ratios are:

	<u>Including S-T Debt</u>	<u>Excluding S-T Debt</u>
7 2003	52.7%	59.3%
8 2004	53.4%	62.7%
9 2005	49.5%	59.2%
10 2006	58.4%	62.3%
11 2007	53.9%	65.1%
12 March 31, 2008	53.5%	53.7%

13
14 This reflects a somewhat variable common equity composition in recent years.

15 Q. HOW DO THESE CAPITAL STRUCTURE RATIOS COMPARE TO THE GAS
16 DISTRIBUTION UTILITY INDUSTRY?
17

18 A. I prepared Schedule 6 to make this comparison. Page 1 of this schedule shows the 2003-
19 2007 capital structure ratios of my proxy group of LDC's, excluding short-term debt.
20 Page 2 of Schedule 6 indicates the 2003-2007 capital structure ratios for this group,
21 including short-term debt. The average common equity ratios are:

	<u>Including S-T Debt</u>	<u>Excluding S-T Debt</u>
22 2003	43%	50.5%
23 2004	43%	51.7%
24 2005	44%	51.8%
25 2006	47%	52.1%
26 2007	46%	54.0%

27
28 These common equity ratios are somewhat lower than those of Equitable Resources.
29

1 Q. WHAT CAPITAL STRUCTURE RATIOS HAS EQUITABLE GAS REQUESTED
2 IN THIS PROCEEDING?

3
4 A. Company witness Frank J. Hanley requests use of the following (hypothetical) capital
5 structure:

Capital Item	Percent
Long-Term Debt	40.90%
Short-Term Debt	9.10%
Common Equity	50.00%

6
7
8
9
10
11 This hypothetical capital structure is largely based on the recent capital structure of his
12 proxy group.

13 Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS
14 PROCEEDING?

15
16 A. I have modified the proposed hypothetical capital structure that is contained in the
17 Company's filing, to reflect a slightly lower common equity ratio – 47 percent versus the
18 50 percent proposed by Mr. Hanley. I note that the capital structure proposed by Mr.
19 Hanley does include short-term debt. I also favor the inclusion of short-term debt in a
20 utility's capital structure for rate making purposes, especially when it can be shown to be
21 consistently financing a portion of rate base. I propose use of a 47 percent hypothetical
22 common equity ratio since this more closely matches the average common equity ratio of
23 my proxy group (Schedule 6, page 2) as well as Mr. Hanley's proxy group (page 17 of
24 his testimony). I have allocated the remaining 53 percent of debt in the same manner as
25 does Mr. Hanley on page 18 of his testimony.
26

1 Q. WHAT ARE THE COST RATES OF LONG-TERM DEBT AND SHORT-TERM
2 DEBT IN THE COMPANY'S APPLICATION?
3

4 A. The Company's filing cites a cost of long-term debt of 6.39 percent and a cost of short-
5 term debt of 3.26 percent. I use these cost rates in my cost of capital analyses.

6 Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME
7 DEGREE OF PRECISION AS THE COSTS OF DEBT?
8

9 A. No. The cost rates of debt are largely determined by interest payments, issue prices, and
10 related expenses. The cost of common equity, on the other hand, cannot be precisely
11 quantified, primarily because this cost is an opportunity cost. There are, however, several
12 models which can be employed to estimate the cost of common equity. Three of the
13 primary methods - DCF, CAPM, and CE - are developed in the following sections of my
14 testimony.
15

1 **VII. SELECTION OF PROXY GROUP**

2 **Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR**
3 **EQUITABLE GAS?**

4
5 A. Equitable Gas is not a publicly-traded company. Equitable Resources is a publicly-traded
6 company. Consequently, it is possible to directly apply cost of equity models to
7 Equitable Resources. However, this Company's diversified and largely non-regulated
8 operations severely compromises the use of this Company's cost of equity as a proxy for
9 Equitable Gas' regulated operations. In addition, it is customary to analyze groups of
10 comparison or "proxy" companies to determine the cost of common equity for public
11 utilities.

12 I have examined such a group for comparison to Equitable Gas. The companies
13 contained in the proxy group are shown on Schedule 7. This group of proxy companies
14 shown on Schedule 7 is derived from the group of gas distribution companies followed
15 by Value Line. However, I did not include Energen, New Jersey Resources and UGI as
16 they fall outside the criteria I used to select my proxy group. The following criteria were
17 employed:

- 18 (1) Inclusion in Value Line Natural Gas Utility Group;
- 19 (2) Currently pays dividends;
- 20 (3) Percent regulated gas revenues of 50 percent or greater;
- 21 (4) S&P and/or Moody's bond ratings of Triple B or greater;
- 22 (5) Common equity ratio of 40 percent to 55 percent; and,
- 23 (6) Value Line Safety of 1, 2, or 3.
- 24

1 I chose these criteria in order to focus on companies that are primarily LDC's with
2 similar risk and operating characteristics of Equitable Gas. This group, which reflects a
3 representative sample of LDC's, is a more appropriate proxy for Equitable Gas. I note
4 that this proxy group is identical to the group of nine natural gas utilities Company
5 witness Mr. Hanley utilized in this testimony.

1 **VIII. DISCOUNTED CASH FLOW ANALYSIS**

2 **Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE**
3 **DISCOUNTED CASH FLOW MODEL?**

4
5 A. The discounted cash flow (DCF) model is one of the oldest, as well as the most
6 commonly-used, models for estimating the cost of common equity for public utilities.
7 The DCF model is based on the "dividend discount model" of financial theory, which
8 maintains that the value (price) of any security or commodity is the discounted present
9 value of all future cash flows. This Commission has primarily relied on the DCF model
10 in setting the cost of equity for utilities.

11 The most common variant of the DCF model assumes that dividends are expected
12 to grow at a constant rate. This variant of the dividend discount model is known as the
13 constant growth or Gordon DCF model. In this framework cost of capital is derived by
14 the following formula:

$$K = \frac{D}{P} + g$$

15
16 where: P = current price
17 D = current dividend rate
18 K = discount rate (cost of capital)
19 g = constant rate of expected growth
20

21 This formula essentially recognizes that the return expected or required by investors is
22 comprised of two factors: the dividend yield (current income) and expected growth in
23 dividends (future income).
24

1 **Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.**

2 A. I have utilized the constant growth DCF model. In doing so, I have combined the current
3 dividend yield for the group of proxy utility stocks described in the previous section with
4 several indicators of expected dividend growth.

5 **Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF**
6 **EQUATION?**

7
8 A. There are several methods that can be used for calculating the dividend yield component.
9 These methods generally differ in the manner in which the dividend rate is employed (i.e.
10 current versus future dividends or annual versus quarterly compounding of dividends). I
11 believe the most appropriate dividend yield component is a quarterly compounding
12 variant, which is expressed as follows:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

13
14 This dividend yield component recognizes the timing of dividend payments and dividend
15 increases.

16 The P_0 in my yield calculation is the average (of high and low) stock price for
17 each proxy company for the most recent three month period (June-August 2008). The D_0
18 is the current annualized dividend rate for each proxy company.

19 **Q. HOW HAVE YOU ESTIMATED THE DIVIDEND GROWTH COMPONENT OF**
20 **THE DCF EQUATION?**

21
22 A. The dividend growth rate component of the DCF model is usually the most crucial and
23 controversial element involved in using this methodology. The objective of estimating
24 the dividend growth component is to reflect the growth expected by investors that is
25 embodied in the price (and yield) of a company's stock. As such, it is important to
26 recognize that individual investors have different expectations and consider alternative

1 indicators in deriving their expectations. This is evidenced by the fact that every
2 investment decision resulting in the purchase of a particular stock is matched by another
3 investment decision to sell that stock.

4 A wide array of indicators exist for estimating the growth expectations of
5 investors. As a result, it is evident that no single indicator of growth is always used by all
6 investors. It, therefore, is necessary to consider alternative indicators of dividend growth
7 in deriving the growth component of the DCF model.

8 I have considered five indicators of growth in my DCF analyses. These are:

- 9 1. Years 2003-2007 (5-year average) earnings retention, or fundamental growth;
- 10 2. Five year average of historic growth in earnings per share (EPS), dividends per
11 share (DPS), and book value per share (BVPS);
- 12 3. Years 2008, 2009, and 2011-2013 projections of earnings retention growth (per
13 Value Line);
- 14 4. Years 2005-2007 to 2011-2013 projections of EPS, DPS, and BVPS (per Value
15 Line); and,
- 16 5. Five year projections of EPS growth as reported by First Call (per Yahoo!
17 Finance).

18 I believe this combination of growth indicators is a representative and appropriate
19 set with which to begin the process of estimating investor expectations of dividend
20 growth for the groups of proxy companies. I also believe that these growth indicators
21 reflect the types of information that investors consider in making their investment
22 decisions. As I indicated previously, investors have an array of information available to

1 them, all of which should be expected to have some impact on their decision-making
2 process.

3 **Q. PLEASE DESCRIBE YOUR INITIAL DCF CALCULATIONS.**

4 A. Schedule 8 presents my DCF analysis. Page 1 shows the calculation of the "raw"
5 (i.e. prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and
6 3 show the growth rate for the group of proxy companies. Page 4 shows the "raw" DCF
7 calculations, which are presented on several bases: mean, median, and high values.
8 These results can be summarized as follows:

	Mean	Median	Mean High ¹	Median High ¹
Proxy Group	8.7%	8.2%	9.3%	8.9%

¹ Using only the highest growth rate.

13 I note that the individual company DCF calculations shown on Schedule 8 should not be
14 interpreted to reflect the expected cost of capital for the proxy group; rather, the
15 individual values shown should be interpreted as alternative information considered by
16 investors.

17 The DCF results in Schedule 8 indicate average (mean and median) DCF cost
18 rates of about 8.2 percent to 8.7 percent. The highest DCF rates (i.e. using the highest
19 growth rates only) are about 8.9 percent to 9.3 percent.

20 **Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?**

21 A. Based upon my analyses, I believe a range of 9 percent to 9.3 percent represents the
22 current DCF cost of equity for the proxy group. This is approximated by the upper
23 portion of the average/mean values but is below the top DCF calculations for the group

1 examined in the previous analysis. I recommend a cost of equity of 9 percent to 9.3
2 percent for Equitable Gas.

3

1 **IX. CAPITAL ASSET PRICING MODEL ANALYSIS**

2 **Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF**
3 **THE CAPITAL ASSET PRICING MODEL.**

4
5 A. The Capital Asset Pricing Model (CAPM) is a version of the risk premium method. The
6 CAPM describes and measures the relationship between a security's investment risk and
7 its market rate of return. The CAPM was developed in the 1960s and 1970s as an
8 extension of modern portfolio theory (MPT), which studies the relationships among risk,
9 diversification, and expected returns.

10 **Q. HOW IS THE CAPM DERIVED?**

11 A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

12
13 where: K = cost of equity

14 R_f = risk free rate

15 R_m = return on market

16 β = beta

17 $R_m - R_f$ = market risk premium

18 As noted previously, the CAPM is a variant of the risk premium method. I believe the
19 CAPM is generally superior to the simple risk premium method because the CAPM
20 specifically recognizes the risk of a particular company or industry (i.e., beta), whereas
21 the simple risk premium method does not, but rather assumes the same cost of equity for
22 all companies exhibiting similar bond ratings.

23 **Q. WHAT COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM**
24 **ANALYSES?**

25
26 A. I have performed CAPM analyses for the same group of proxy utilities evaluated in my
27 DCF analyses.

1 **Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?**

2 A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level
3 of return that can be achieved without accepting any risk.

4 In CAPM applications, the risk-free rate is generally recognized by use of U.S.
5 Treasury securities. Two general types of U.S. Treasury securities are often utilized as
6 the R_f component, short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

7 I have performed CAPM calculations using the three month average yield (June-
8 August 2008) for 20-year U.S. Treasury bonds. Over this three month period, these
9 bonds had an average yield of 4.63 percent.

10 **Q. WHAT IS BETA AND WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?**

11 A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation
12 to the overall market. Betas of less than 1 are considered less risky than the market,
13 whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas
14 below 1. I utilized the most recent Value Line betas for each company in the group of
15 proxy utilities.

16 **Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT?**

17 A. The market risk premium component ($R_m - R_f$) represents the investor-expected premium
18 of common stocks over the risk-free rate, or government bonds. For the purpose of
19 estimating the market risk premium, I considered alternative measures of returns of the
20 S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury
21 bonds.

22 First, I have compared the actual annual returns on equity of the S&P 500 with the
23 actual annual yields of U.S. Treasury bonds. Schedule 9 shows the return on equity for

the S&P 500 group for the period 1978-2007 (all available years reported by S&P). This Schedule also indicates the annual yields on 20-Year U.S. Treasury bonds, as well as the annual differentials (i.e. risk premiums) between the S&P 500 and U.S. Treasury 20-Year bonds. Based upon these returns, I conclude that this measure of the risk premium is about 6.45 percent.

I have also considered the total returns (i.e. dividends/interest plus capital gains/losses) for the S&P 500 group as well as for long-term government bonds, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2007 period, which are as follows:

	<u>S&P 500</u>	<u>L-T Gov't Bonds</u>	<u>Risk Premium</u>
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.4%	4.9%

I conclude from this that the expected risk premium is about 5.9 percent (i.e. average of all three risk premiums - 6.4 percent from Schedule 9 and 6.5 percent arithmetic and 4.9 percent geometric from Morningstar). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 10 shows my CAPM calculations using this risk premium. The results are:

	<u>Mean</u>	<u>Median</u>
Proxy Group	9.4%	9.4%

1 Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF
2 EQUITY?

3
4 A. The CAPM results collectively indicate a cost of about 9.4 percent for the group of
5 comparison utilities. I conclude that the CAPM cost of equity for Equitable Gas is 9.4
6 percent.

7

1 X. **COMPARABLE EARNINGS ANALYSIS**

2 Q. **PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.**

3 A. The CE method is derived from the "corresponding risk" referred to by the Bluefield and
4 Hope cases. This method is thus based upon the economic concept of opportunity cost.
5 As previously noted, the cost of capital is an opportunity cost: the prospective return
6 available to investors from alternative investments of similar risk.

7 The CE method is designed to measure the returns expected to be earned on the
8 original cost book value of similar risk enterprises. Thus, this method provides a direct
9 measure of the fair return, since it translates into practice the competitive principle upon
10 which regulation rests.

11 The CE method normally examines the experienced and/or projected returns on
12 book common equity. The logic for returns on book equity follows from the use of
13 original cost rate base regulation for public utilities, which uses a utility's book common
14 equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate
15 of return which is then applied (multiplied) to the book value of rate base to establish the
16 dollar level of capital costs to be recovered by the utility. This technique is thus
17 consistent with the rate base methodology used to set utility rates.

18 Q. **HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR**
19 **ANALYSIS OF EQUITABLE GAS' COMMON EQUITY COST?**

20
21 A. I conducted the CE methodology by examining realized returns on equity for several
22 groups of companies and evaluating the investor acceptance of these returns by reference
23 to the resulting market-to-book ratios. In this manner it is possible to assess the degree to
24 which a given level of return equates to the cost of capital. It is generally recognized for
25 utilities that market-to-book ratios of greater than one (i.e. 100%) reflect a situation

1 where a company is able to attract new equity capital without dilution (i.e. above book
2 value). As a result, one objective of a fair rate of return is the maintenance of stock
3 prices at or about book value. There is no regulatory obligation to set rates designed to
4 maintain a market-to-book ratio significantly above one.

5 I would further note that my CE analysis is based upon market data (through the
6 use of market-to-book ratios) and is thus essentially a market test. As a result, my
7 comparable earnings analysis is not subject to the criticisms occasionally made by some
8 who maintain that past earned returns do not represent the cost of capital. In addition, my
9 comparable earnings analysis uses prospective returns and thus is not backward looking.

10 **Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?**

11 A. My CE analysis considers the experienced equity returns of the proxy group of utilities
12 for the period 1992-2007 (i.e. last sixteen years). The CE analysis requires that I examine
13 *a relatively long period of time in order to determine trends in earnings over at least a full*
14 *business cycle.* Further, in estimating a fair level of return for a future period, it is
15 important to examine earnings over a diverse period of time in order to avoid any undue
16 influence from unusual or abnormal conditions that may occur in a single year or shorter
17 period. Therefore, in forming my judgment of the current cost of equity I have focused
18 on two periods: 2003-2007 (the last five years which is the average length of a business
19 cycle) and 1992-2001 (the most recent complete albeit lengthy business cycle).

20 **Q. PLEASE DESCRIBE YOUR CE ANALYSIS.**

21 A. Schedules 11 and 12 contain summaries of experienced returns on equity for several
22 groups of companies, while Schedule 13 presents a risk comparison of utilities versus
23 unregulated firms.

Schedule 11 shows the earned returns on average common equity and market-to-book ratios for the group of proxy utilities. These can be summarized as follows:

	Proxy Group
Historic ROE ¹	
Mean	11.6-11.7%
Median	11.7-11.9%
Historic M/B ²	
Mean	177-180%
Median	176-181%
Prospective ROE ³	
Mean	11.4-12.2%
Median	11.5-12.0%

¹ See Schedule 11, page 1, columns titled "1992-2001 Average" and "2002-2006 Average."

² See last two columns of Schedule 11, page 2.

³ See last three columns of Schedule 11, page 1.

These results indicate that historic returns of 11.6-11.9 percent have been adequate to produce market-to-book ratios of 176-181 percent for the group of proxy utilities. Furthermore, projected returns on equity for 2008, 2009, and 2011-2013 are within a range of 11.4 percent to 12.2 percent for the utility group. These relate to 2007 market-to-book ratios of over 185 percent.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 12 presents the earned return on equity and market-to book ratios for the S&P 500 group over the past sixteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from

1 14.7 percent to 15.0 percent with market-to book ratios ranging between 282 percent and
2 341 percent.

3 **Q. HOW CAN THE ABOVE INFORMATION BE USED TO CHECK THE COST OF**
4 **EQUITY FOR EQUITABLE GAS?**
5

6 A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an
7 indication of the level of return realized and expected in the regulated and competitive
8 sectors of the economy. In order to apply these returns to the cost of equity for proxy
9 utilities, however, it is necessary to compare the risk levels of the utility industry with
10 those of the competitive sector. I have done this in Schedule 13, which compares several
11 risk indicators for the S&P 500 group and the utility group. The information in this
12 schedule indicates that the S&P 500 group is more risky than the utility proxy group.

13 **Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?**

14 A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis
15 indicates that the cost of equity for the proxy utilities is 9.0 percent to 10.0 percent.
16 Recent returns of 11.6 percent to 11.9 percent have resulted in market-to-book ratios of
17 175 and greater. Prospective returns of 11.4 percent to 12.2 percent result in anticipated
18 market-to-book ratios of over 185 percent. As a result, it is apparent that returns below
19 this level would result in market-to-book ratios of well above 100 percent. An earned
20 return of 9.0 percent to 10.0 percent should thus result in a market-to-book ratio of over
21 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially
22 exceed 100 percent indicates that historic and prospective returns of 11 percent to 12
23 percent reflect earnings levels that exceed the cost of equity for those regulated
24 companies.

1 Please also note that my CE analysis is not based on a mathematic formula
2 approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends
3 and current conditions in equity markets. Further, it is based on the direct relationship
4 between returns on common stock and market-to-book ratios of common stock. In utility
5 rate setting, a fair rate of return is based on the utility's assets (i.e., rate base) and the
6 book value of the utility's capital structure. As stated earlier, maintenance of a
7 financially stable utility's market-to-book ratio at or about 100% is fully adequate to
8 maintain the utility's financial stability. On the other hand, a market price of a utility's
9 common stock that is 150 percent or more above the stock's book value is indicative of
10 earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected
11 earnings do not directly translate into a utility's reasonable cost of equity. Rather, they
12 must be viewed in relation to the market-to-book ratios of the utility's common stock.

13 My 9.0 percent to 10.0 percent CE recommendation reflects the fact that historic
14 equity returns of 11.6 percent to 11.9 percent have resulted in market-to-book ratios of
15 180 percent or greater, which demonstrate that the equity returns exceed the cost of
16 capital. Likewise, projected returns of about 11 percent to 12 percent relate to 2007
17 market-to-book ratios of over 180 percent. My 9.0 percent to 10.0 percent CE
18 recommendation is not designed to result in market-to-book ratios as low as 1.0 for
19 Equitable Gas. Rather, it is based on current market conditions and the proposition that
20 ratepayers should not be required to pay rates based on earnings levels that result in
21 excessive market-to-book ratios.

1 **XI. RETURN ON EQUITY RECOMMENDATION**

2 **Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY**
3 **ANALYSES.**

4
5 A. My three methodologies produce the following:

6 Discounted Cash Flow 9.0-9.3%

7 Capital Asset Pricing Model 9.4%

8 Comparable Earnings 9.0-10.0%

9 My overall conclusion from these results is an overall range of 9.0 percent to 10 percent,
10 which focuses on the respective ranges of my individual model findings. I recommend a
11 cost of equity of 9.3 percent for Equitable Gas, which reflects the upper end of the DCF
12 range and is verified by the results of the CAPM and CE methodologies. As I noted
13 previously, the DCF method is the preferred methodology of this Commission.
14

1 **XII. TOTAL COST OF CAPITAL**

2 **Q. WHAT IS THE TOTAL COST OF CAPITAL FOR EQUITABLE GAS?**

3 A. Schedule 1 reflects the total cost of capital for the Company using my proposed
4 hypothetical capital structure and cost of long-term debt, short-term debt, and my
5 common equity cost recommendations. The resulting total cost of capital is a range of
6 7.31 percent to 7.78 percent, with a 7.45 percent cost of capital attributable to a 9.3
7 percent cost of equity. I recommend that this 7.45 total cost of capital be established for
8 Equitable Gas.

9 **Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE**
10 **COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS**
11 **FINANCIAL INTEGRITY?**
12

13 A. Yes, it does. Schedule 14 shows the pre-tax coverage that would result if Equitable Gas
14 earned the mid-point of my cost of capital recommendation. As the results indicate, the
15 mid-point of my recommended range would produce a coverage level in excess of the
16 benchmark range for an A rated utility. In addition, the debt ratio is superior to the
17 benchmark level for an A rated utility.
18

XIII. COMMENTS ON COMPANY TESTIMONY

Q. HAVE YOU REVIEWED THE COST OF CAPITAL TESTIMONY OF EQUITABLE GAS WITNESS FRANK J. HANLEY?

A. Yes, I have.

Q. WHAT IS YOUR UNDERSTANDING OF HIS COST OF CAPITAL RECOMMENDATION FOR EQUITABLE GAS?

A. Mr. Hanley is recommending a total cost of capital for Equitable Gas of 8.89 percent, as follows:

	<u>Ratios */</u>	<u>Cost</u>	<u>Weighted Cost</u>
Long-Term Debt	40.90%	6.39%	2.61%
Short-Term Debt	9.10%	3.29%	0.30%
Common Equity	50.00%	11.95%	5.96%
			<u>8.89%</u>

*/ Equitable Resources cost rates applied to a hypothetical capital structure.

Q. HOW DOES HE DERIVE HIS COST OF EQUITY RECOMMENDATION?

A. Mr. Hanley performs the following cost of equity analyses and derives the indicated results:

	<u>Proxy Group of 9 Value Line LDCs</u>
Discounted Cash Flow	9.58%
Risk Premium	11.27%
Capital Asset Pricing Model	10.78%
Comparable Earnings	18.06%
Indicated Cost of Equity	11.00%
Cost of Equity Adjustments	
Size Adjustment	0.25%
Lack of Rate Design Protection	0.20%
Service Area Competition	0.45%
Total	0.95%
Recommended Cost of Equity	11.95%

His recommendation for Equitable Gas is 11.95 percent.

1 Q. DO YOU HAVE ANY DISAGREEMENTS WITH ANY OR ALL OF MR.
2 HANLEY'S METHODOLOGIES AND RECOMMENDATIONS?
3

4 A. Yes, I have disagreements with each of his cost of equity methodologies and conclusions,
5 as well as his proposed 0.95 percent "investment risk adjustments" for Equitable Gas. I
6 note that, even though Mr. Hanley claims (page 4, lines 17-18) his methodologies and
7 conclusions are predicated on the Efficient Market Hypothesis (EMH), many of the
8 "adjustments" he makes to the models are in violation of the EMH.

9 Q. PLEASE BEGIN WITH HIS DCF MODEL AND CONCLUSIONS.

10 A. Mr. Hanley's 9.58 percent DCF conclusion is shown on Equitable Exhibit 5A, Schedule
11 7. It is apparent from his exhibit that Mr. Hanley only considers the DCF results of three
12 of the nine companies in his proxy group due to his exclusion of all DCF rates of 9.5
13 percent or less, which he rationalizes as "the lowest rate awarded to a gas distribution
14 company or to the gas operations of a combination electric & gas company during the
15 twelve months ended March 31, 2008." I do not believe it is appropriate to exclude
16 virtually all of his DCF results for this reason.

17 Q. MR. HANLEY MAINTAINS IN HIS TESTIMONY ON PAGES 26-31 THAT THE
18 DCF MODEL CANNOT BE USED AS AN ESTIMATE OF THE COST OF
19 EQUITY FOR A UTILITY WHEN THE MARKET PRICE OF UTILITY
20 STOCKS EXCEEDS THE BOOK VALUE. DO YOU AGREE WITH THIS
21 POSITION?
22

23 A. No, I do not. Knowledgeable and/or informed investors are aware of the fact that most
24 utilities have their rates set based on the book value of their assets (i.e., rate base and
25 capital structure). This knowledge is reflected in the prices that investors are willing to
26 pay for stocks and thus is reflected in DCF cost rates. To make a modification of the
27 DCF cost rates, as Mr. Hanley proposes, amounts to an attempt to "reprice" stock values
28 in order to develop a DCF cost rate more in line with what he thinks the results should be.

1 This is clearly a violation of the principle of "the EMH", which Mr. Hanley cites
2 extensively in his testimony. If one believes that markets are efficient, there is no reason
3 to modify either stock prices or market models based on stock prices.

4 **Q. ON PAGES 27-28, MR. HANLEY STATES HIS VIEW THAT WHEN MARKET**
5 **PRICES EXCEED THE BOOK VALUE, THE DCF RESULTS UNDERSTATE**
6 **THE COST OF EQUITY. HE ALSO POSTULATES THAT WHEN THE**
7 **REVERSE OCCURS, THE DCF RESULTS WOULD OVERSTATE THE COST**
8 **OF CAPITAL. DO YOU HAVE ANY COMMENTS ON THIS?**

9
10 A. Yes, I do. I was testifying in utility rate cases in the 1970s and early 1980s, a period
11 during which utility stock prices were frequently well below book value. Based on my
12 personal recollections, I cannot remember a single instance in which a utility-sponsored
13 cost of capital witness advocated that the DCF model overstated the cost of equity. I also
14 never have taken this position.

15 I also note that I testified in a large number of rate proceedings in which Mr.
16 Hanley and members of his firm testified. I can recall of no instances in which any AUS
17 witness testified that the DCF result overstated the cost of equity.

18 **Q. PLEASE DESCRIBE MR. HANLEY'S RISK PREMIUM METHODOLOGY AND**
19 **CONCLUSIONS.**

20
21 A. Mr. Hanley's risk premium methodology combines his estimate (6.26 percent) of the
22 prospective yield on A rated public utility bonds, adjusted by 0.14 percent (for proxy
23 group) to reflect lower debt ratings with "equity risk premiums" of 4.87 percent and 5.86
24 percent to arrive at a risk premium cost of equity of 11.27 percent to 12.26 percent.

25 **Q. DO YOU AGREE WITH HIS METHODOLOGY AND CONCLUSIONS?**

26 A. No, I do not. I disagree with the equity risk premium level of 4.87 percent to 5.86
27 percent he employs. Mr. Hanley uses two studies to derive this risk premium and
28 averages the two results. First, he compares total returns for the S&P over the 1926-2007

1 period with yields on corporate bonds over the same period, as well as forecasted total
2 returns on stocks versus prospective yields on corporate bonds to derive an equity risk
3 premium of 6.20 percent. He then multiplies the average by the betas of his LDC proxy
4 groups (in a CAPM context) to develop his 5.39 percent to 7.37 percent equity risk
5 premium. Use of total returns over the 1926-2007 period, in connection with bond yields
6 over the same long period, does not imply that any such relationships are expected by
7 investors in 2008. First, his methodology is a mis-match since its compares holding
8 period returns (i.e., capital gains/losses plus income) with yields on bonds (i.e., only
9 income). In addition, the 1926-2007 period was heavily influenced by the Great
10 Depression, World War II, the high inflation/interest rate environment of the
11 1970s/1980s, etc. Such factors are not prevalent currently and have the effect of inflating
12 risk premiums over those expected by investors. I believe Mr. Hanley's analyses over-
13 state the required risk premiums at the present time. The fact that Mr. Hanley's
14 forecasted equity risk premium is some two hundred and sixty basis points less than the
15 historic risk premium is further indication of this concern.

16 In addition, I find it inconsistent on his part to defend use of historic data going
17 back to 1926 in his risk premium and CAPM analyses, and to then primarily ignore
18 historic data in his DCF analyses. I do not see how an investor would place equal weight
19 between returns in 1926 and 2007 in one type of analysis (i.e., risk premium and CAPM)
20 and then give little weight to recent (i.e., 5 years) experience in DCF analysis.

1 **Q. PLEASE DESCRIBE MR. HANLEY'S CAPM ANALYSES.**

2 A. Mr. Hanley performs two CAPM analyses. His first CAPM is a "traditional" CAPM,
3 where he concludes that 12.69 percent is the CAPM cost. This uses a risk free rate of
4 4.50 percent (projected yield on 30-year U.S. Treasury bonds).

5 Mr. Hanley also performs an "empirical" CAPM analysis, wherein he assigns 75
6 percent weight to actual betas for the proxy groups of gas utilities and a 25 percent
7 weight to an assumed beta of 1.0 (i.e., the market beta). I disagree with this empirical
8 CAPM.

9 The use of an empirical CAPM overstates the cost of equity for companies with
10 betas below that of the market. What the empirical CAPM actually does is inflate the
11 CAPM cost for the selected company or industry on one-fourth of its equity and assumes
12 that one-fourth of the company has the risk of the overall market. This is not appropriate
13 for Equitable Gas or for other utilities because it essentially creates a hypothetical beta
14 that is used in the place of the actual beta. Investors are provided actual betas by
15 organizations such as Value Line and it is reasonable to believe that investors rely upon
16 these betas to some extent in making investment decisions. Mr. Hanley has provided no
17 rationale or reasons to believe that investors would ignore these published betas and
18 instead rely on hypothetical betas that are neither published nor readily available.

19 **Q. MR. HANLEY ALSO MAINTAINS THAT THE TRADITIONAL CAPM**
20 **UNDERSTATES THE COST OF EQUITY FOR COMPANIES WITH BETAS**
21 **BELOW 1.0. DO YOU AGREE WITH HIS POSITION?**
22

23 A. No, I do not. Again, Mr. Hanley fails to accept the fact that betas are determined using
24 actual stock price movements and reflect actual decisions by investors. If one accepts the

1 Efficient Market Hypothesis, as he does, there is no reason to modify the actual stock
2 price movements and substitute alternative movements, as the empirical CAPM does.

3 **Q. PLEASE SUMMARIZE MR. HANLEY'S COMPARABLE EARNINGS**
4 **METHOD.**

5
6 A. Mr. Hanley's comparable earnings analysis examines the forecasted returns on
7 equity for two groups of 17 non-utility companies which he perceives as being of similar
8 risk to Equitable Gas and his LDC proxy group. For the 17 companies, he calculated a 5-
9 year forecasted return of 18.06 percent.

10 I believe this analysis is an improper mechanism for estimating the cost of
11 common equity for Equitable Gas. The equivalence of beta values (i.e., the basis for his
12 selection of comparison companies) does not indicate that the expected earnings and cost
13 of common equity for these non-utilities and utilities are the same. The projected 3-5
14 year returns for the non-utilities is 18.06 percent in Mr. Hanley's Equitable Exhibit 5A,
15 Schedule 14 whereas the respective returns for Mr. Hanley's proxy group of LDC utility
16 companies is only 11.5-12.2 percent (my Schedule 11). This difference in returns
17 demonstrates that utilities are able to maintain similar Value Line betas to non-utilities
18 even though their expected earnings are substantially lower than those of the non-utilities.
19 This result indicates that the expected earnings for the non-utilities are greater than for
20 utilities such as Equitable Gas.

21 **Q. MR. HANLEY CONCLUDES THAT THE "INDICATED COST OF EQUITY"**
22 **FOR HIS PROXY GROUP IS 11.0 PERCENT, WHICH HE INCREASES BY**
23 **SOME 0.95 PERCENT TO REFLECT HIS PERCEPTION OF A REQUIRED**
24 **"INVESTMENT RISK ADJUSTMENTS" FOR EQUITABLE GAS. WHAT IS**
25 **YOUR RESPONSE TO THIS PROPOSED ADJUSTMENT?**

26
27 A. I disagree with Mr. Hanley's proposed investment risk adjustments for Equitable Gas.
28 Mr. Hanley's 0.95 percent investment risk adjustments (which forms the basis for his

1 11.95 percent recommendation for Equitable Gas) are not proper and should not be
2 approved by the Commission.

3 As noted previously, Mr. Hanley is proposing three separate risk adjustments for
4 Equitable Gas. These are: 1) a size adjustment; 2) a lack of rate design protection
5 adjustment; and 3) a service area competition adjustment. He maintains that each of
6 these three factors distinguishes Equitable Gas from the proxy group of natural gas
7 utilities and that Equitable Gas has more risk and therefore requires a higher return on
8 equity than the proxy group's cost of equity.

9 I note, first of all, that the size adjustment focuses on the size of Equitable Gas,
10 not Equitable Resources. This is an improper comparison. Equitable Gas does not raise
11 equity capital, as this is done by Equitable Resources which is the publicly traded entity.
12 Equitable Resources is not a small company. According to AUS Utility Reports, the
13 most recently-reported total revenues of Equitable Resources is \$1.4 billion and the net
14 plant is \$3 billion. These compare favorably with the other "natural gas distribution &
15 integrated natural gas companies" covered in this publication. In addition, Equitable
16 Resources is listed as a "large cap" stock by Value Line. Clearly, Equitable Resources is
17 not a small company and deserves no size adjustment. I note that, prior to the recent
18 reorganization, Equitable Gas was a division of Equitable Resources and was not a
19 distinct company. There is no rationale for the reorganization to be used as a criteria for
20 Equitable Gas to be viewed as more risky than was the case prior to the reorganization.
21 In fact, as I noted earlier in my testimony, Equitable Gas should be viewed as less risky
22 after the reorganization.

1 I also disagree with Mr. Hanley's adjustment for "lack of rate design protection."
2 This adjustment is largely based on Mr. Hanley's perception that most other gas
3 distribution companies have some sort of decoupling and weather adjustments that have
4 the effect of reducing their risk relative to that of Equitable Gas. What Mr. Hanley's
5 claims do not address is the fact that many of the proxy group companies have multiple
6 subsidiaries and/or operate in multiple states. As a result, the existence of some
7 decoupling and/or weather normalization clauses does not indicate that these proxy group
8 companies are completely insulated from weather and usage variability. In addition, the
9 existing decoupling clauses differ from company to company and jurisdiction to
10 jurisdiction, which is why we cannot conclude that all proxy companies with some form
11 of decoupling have the same level of "rate design protection." Finally, it is apparent that
12 most of the proxy companies have non-regulated operations that have no rate design
13 protection. This portion of their revenues thus are not subject to decoupling and thus the
14 market cannot make any allowance for the perception of these factors.

15 Finally, I disagree with Mr. Hanley's 50 basis point adjustment for Equitable Gas'
16 perceived competition from other LDCs. Mr. Hanley describes this as an "extraordinary
17 risk" and recommends a 50 basis point adjustment to account for this. It is noteworthy
18 that Equitable gas offers distribution rate discounts to certain industrial and commercial
19 customers who have competitive options to buy natural gas from other LDCs. However,
20 Equitable has asked its captive ratepayers to pay for these discounts through their rates. I
21 am informed that these discounts are claimed to be some \$23 million in the current case.
22 It is thus apparent that Equitable Gas' customers are already being asked to pay for this
23 perceived risk in the present base rate filing. Mr. Hanley does not acknowledge these

1 payments in his risk assessment. In fact, the adoption of Mr. Hanley's proposed
2 adjustment would amount to a double-recovery of the competition impact on Equitable.
3 Finally, Mr. Hanley's argument is another reason why LDC gas on gas competition at the
4 expense of captive customers is not in the public interest.

5
6 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

7 A. Yes, it does.

8 104856.doc

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

ATTACHMENT I
TO THE
DIRECT TESTIMONY OF
DAVID C. PARCELL

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

RATE OF RETURN

OCTOBER 8, 2008

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to

a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts
 Board of Directors 1992-2000
 Secretary/Treasurer 1994-1998
 President 1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial

Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review, Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, :
 :
 v. : Docket No. R-2008-2029325, et al
 :
 Equitable Gas Company :

Independent Oil and Gas Association of :
 Pennsylvania :
 v. : C-20066800
 Equitable Gas Company :

SCHEDULES
TO THE
DIRECT TESTIMONY OF
DAVID C. PARCELL

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

RATE OF RETURN

OCTOBER 8, 2008

EQUITABLE GAS COMPANY TOTAL COST OF CAPITAL

Item	Percent	Cost	Weighted Cost	
Long-Term Debt	43.35%	6.39%	2.77%	
Short-Term Debt	9.65%	3.26%	0.31%	
Common Equity	47.00%	9.00%	10.00%	4.23%
				4.70%
Total	100.00%		7.31%	7.78%
			7.45%	With 9.3%

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un- employment Rate	Consumer Price Index	Producer Price Index
1975 - 1982 Cycle					
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
1983 - 1991 Cycle					
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
1992 - 2001 Cycle					
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.3%	4.2%	2.7%	2.9%
2000	3.7%	4.2%	4.0%	3.4%	3.6%
2001	0.8%	-3.4%	4.7%	1.6%	-1.6%
Current Cycle					
2002	1.6%	-0.1%	5.8%	2.4%	1.2%
2003	2.5%	1.2%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	2.9%	3.3%	5.1%	3.4%	5.4%
2006	2.8%	2.2%	4.6%	2.5%	1.1%
2007	2.0%	1.7%	4.6%	4.1%	6.2%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un- employment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.0%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	2.6%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.8%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.3%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	4.8%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.7%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.8%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	1.5%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.1%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	4.8%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	4.8%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	-0.2%	2.2%	4.8%	6.4%	10.8%
2008					
1st Qtr.	0.9%	1.8%	4.9%	2.8%	9.6%
2nd Qtr.	3.3%	0.3%	5.3%	7.6%	14.0%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1975 - 1982 Cycle							
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
1983 - 1991 Cycle							
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
1992 - 2001 Cycle							
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
Current Cycle							
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2003							
Jan	4.25%	1.17%	4.05%	[1]	6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%		6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%		5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%		5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%		6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%		6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%		6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%				

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
1975 - 1982 Cycle					
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
1983 - 1991 Cycle					
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
1992 - 2001 Cycle					
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
Current Cycle					
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

EQUITABLE RESOURCES, INC.
SEGMENT FINANCIAL INFORMATION
2005 - 2007
(\$millions)

Segment	Revenues	Operating Income	Total Assets
2005			
Equitable Supply	\$489,191 39.0%	\$293,581 85.4%	NA
Equitable Utilities	\$846,457 67.5%	\$98,254 28.6%	NA
Other	-\$81,924 -6.5%	-\$48,023 -14.0%	NA
Equitable Resources, Inc.	\$1,253,724	\$343,812	
2006			
Equitable Supply	\$488,571 38.5%	\$269,164 72.3%	\$1,794,485 54.7%
Equitable Utilities	\$843,164 66.5%	\$125,209 33.6%	\$1,407,024 42.9%
Other	-\$63,825 -5.0%	-\$21,850 -5.9%	\$80,746 2.5%
Equitable Resources, Inc.	\$1,267,910	\$372,523	\$3,282,255
2007			
Equitable Supply	\$501,675 36.8%	\$263,545 84.6%	\$2,262,851 57.5%
Equitable Utilities	\$916,821 67.3%	\$113,447 36.4%	\$1,412,804 35.9%
Other	-\$57,090 -4.2%	-\$65,319 -21.0%	\$261,316 6.6%
Equitable Resources, Inc.	\$1,361,406	\$311,673	\$3,936,971

Source: Equitable Resources, Inc. 2007 Form 10-K.

EQUITABLE RESOURCES, INC.
BOND RATINGS

Date	Unsecured Medium Term Notes		Commercial Paper	
	Moody's	S&P	Moody's	S&P
2003	A2	A	P-1	A-1
2004	A2	A	P-1	A-1
2005	A2	A-	P-1	A-2
2006	A2	A-	P-1	A-2
2007	Baa1	A-	P-2	A-2
2008	Baa1	BBB	P-2	A-2

Source: Company Filing, Response to Standard Data Requests,
Rate of Return Interrogatories, Item 3.

EQUITABLE RESOURCES, INC.
CAPITAL STRUCTURE RATIOS
2003 - 2008
(\$millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2003	\$950,075 52.7% 59.3%	\$653,414 36.2% 40.7%	\$199,600 11.1%
2004	\$1,055,019 53.4% 62.7%	\$626,434 31.7% 37.3%	\$295,499 14.9%
2005	\$1,110,068 49.5% 59.2%	\$766,500 34.2% 40.8%	\$365,300 16.3%
2006	\$1,260,582 58.4% 62.3%	\$763,500 35.3% 37.7%	\$135,999 6.3%
2007	\$1,406,736 53.9% 65.1%	\$753,500 28.9% 34.9%	\$450,000 17.2%
March 31, 2008	\$1,455,425 53.5% 53.7%	\$1,253,500 46.1% 46.3%	\$12,000 0.4%

Source: Company Filing, Exhibit II, Item: § 53.53 II A 1 (a), Sheet 2 of 3.

PROXY GROUP OF NATURAL GAS UTILITIES
COMMON EQUITY RATIOS

COMPANY	2003	2004	2005	2006	2007	Average	2011-2013
AGL Resources	49.7%	46.0%	48.1%	49.8%	49.8%	48.7%	52.5%
Atmos Energy	49.8%	56.8%	42.3%	43.0%	48.0%	48.0%	49.0%
Laclede Group	49.4%	48.3%	51.8%	50.4%	54.6%	50.9%	53.0%
NICOR	60.3%	60.1%	62.5%	63.7%	69.0%	63.1%	80.0%
Northwest Natural Gas	50.3%	54.0%	53.0%	53.7%	53.7%	52.9%	52.0%
Piedmont Natural Gas	57.8%	56.4%	58.6%	51.7%	51.6%	55.2%	54.0%
South Jersey Industries	49.0%	51.0%	55.1%	55.3%	57.3%	53.5%	59.0%
Southwest Gas	34.0%	35.8%	36.2%	39.4%	41.9%	37.5%	48.0%
WGL Holdings	54.3%	57.2%	58.6%	61.5%	60.3%	58.4%	67.0%
Average	50.5%	51.7%	51.8%	52.1%	54.0%	52.0%	57.2%

Source: Value Line Investment Survey.

**PROXY GROUP OF NATURAL GAS UTILITIES
CAPITAL STRUCTURE RATIOS
INCLUDING SHORT-TERM DEBT**

Company	2001	2002	2003	2004	2005	2006	2007
AGL Resources	32%	33%	41%	41%	41%	42%	42%
Atmos Energy	40%	39%	45%	41%	38%	45%	47%
Laclede Group	41%	37%	37%	40%	38%	58%	40%
NICOR	50%	51%	41%	43%	42%	51%	52%
Northwest Natural Gas	46%	48%	50%	49%	47%	48%	47%
Piedmont Natural Gas	51%	54%	53%	53%	48%	46%	45%
South Jersey Industries	32%	34%	41%	31%	45%	44%	50%
Southwest Gas	31%	33%	33%	34%	36%	41%	43%
WGL Holdings	48%	48%	49%	52%	58%	51%	51%
Average	41%	42%	43%	43%	44%	47%	46%

Source: AUS Utility Reports.

SELECTION OF PROXY COMPANIES

Company	Percent Reg Gas Revenues	S&P Bond Rating	Moody's Bond Rating	Common Equity Ratio	Value Line Safety
Value Line Natural Gas Utility Group					
AGL Resources	67%	A-	A3	42%	2
Atmos Energy	56%	BBB	Baa3	47%	2
Energen	42%	BBB+	A1	66%	2
Laclede Group	55%	A	A3	40%	2
New Jersey Resources	34%	A+	NR	49%	1
NICOR	83%	AA	A1	52%	3
Northwest Natural Gas	98%	AA-	A2	47%	1
Piedmont Natural Gas	82%	A	A3	45%	2
South Jersey Industries	65%	A	Baa1	50%	2
Southwest Gas	84%	BBB-	Baa3	43%	3
UGI	19%	NR	A3	35%	2
WGL Holdings	57%	AA-	A2	51%	1

Sources: AUS Utility Reports, Value Line.

COMPARISON COMPANIES DIVIDEND YIELD

COMPANY	June - August, 2008				YIELD
	DPS	HIGH	LOW	AVERAGE	
Proxy Group					
AGL Resources	\$1.68	\$36.42	\$32.20	\$34.31	4.9%
Atmos Energy	\$1.30	\$28.00	\$25.00	\$26.50	4.9%
Laclede Group	\$1.50	\$47.98	\$37.78	\$42.88	3.5%
NICOR	\$1.86	\$46.84	\$38.01	\$42.43	4.4%
Northwest Natural Gas	\$1.50	\$49.56	\$43.66	\$46.61	3.2%
Piedmont Natural Gas	\$1.04	\$29.20	\$25.00	\$27.10	3.8%
South Jersey Industries	\$1.08	\$39.36	\$33.10	\$36.23	3.0%
Southwest Gas	\$0.90	\$31.35	\$27.56	\$29.46	3.1%
WGL Holdings	\$1.42	\$36.22	\$31.64	\$33.93	4.2%
Average					3.9%

Source: Yahoo! Finance.

**COMPARISON COMPANIES
RETENTION GROWTH RATES**

COMPANY	2003	2004	2005	2006	2007	Average	2008	2009	2011-'13	Average
Proxy Group										
AGL Resources	6.6%	5.6%	6.2%	6.3%	5.3%	6.0%	4.5%	5.0%	5.5%	5.0%
Atmos Energy	2.8%	1.7%	2.3%	3.6%	3.0%	2.7%	3.0%	3.5%	4.0%	3.5%
Laclede Group	3.1%	2.7%	3.1%	5.1%	4.3%	3.7%	5.5%	4.5%	5.0%	5.0%
NICOR	1.5%	2.1%	2.3%	5.2%	5.4%	3.3%	2.5%	3.5%	7.0%	4.3%
Northwest Natural Gas	2.6%	2.7%	3.7%	4.5%	6.0%	3.9%	5.0%	5.0%	5.0%	5.0%
Piedmont Natural Gas	3.1%	3.7%	3.6%	2.8%	3.5%	3.3%	4.0%	4.0%	5.0%	4.3%
South Jersey Industries	5.0%	5.9%	6.2%	10.2%	6.7%	6.8%	7.5%	8.0%	9.5%	8.3%
Southwest Gas	1.7%	4.3%	2.2%	5.2%	4.8%	3.6%	4.5%	5.0%	5.5%	5.0%
WGL Holdings	6.2%	4.1%	4.6%	3.1%	3.5%	4.3%	4.5%	4.5%	4.0%	4.3%
Average						4.2%				5.0%

Source: Value Line Investment Survey.

COMPARISON COMPANIES PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '05-'07 to '11-'13 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Proxy Group								
AGL Resources	15.0%	4.0%	10.5%	9.8%	3.0%	4.0%	1.5%	2.8%
Atmos Energy	7.5%	1.5%	9.0%	6.0%	4.5%	2.0%	3.5%	3.3%
Laclede Group	9.5%	1.0%	4.5%	5.0%	4.5%	2.5%	5.5%	4.2%
NICOR	-1.5%	1.0%	4.0%	1.2%	5.0%	0.0%	5.0%	3.3%
Northwest Natural Gas	6.5%	2.0%	3.5%	4.0%	7.0%	5.5%	3.5%	5.3%
Piedmont Natural Gas	6.0%	4.5%	6.5%	5.7%	7.0%	4.0%	4.0%	5.0%
South Jersey Industries	12.5%	4.5%	12.5%	9.8%	6.0%	5.5%	3.5%	5.0%
Southwest Gas	6.0%	0.0%	3.5%	3.2%	7.5%	4.0%	4.0%	5.2%
WGL Holdings	5.0%	1.5%	3.5%	3.3%	3.5%	2.5%	5.0%	3.7%
Average				5.3%				4.2%

Source: Value Line Investment Survey.

**COMPARISON COMPANIES
DCF COST RATES**

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Proxy Group								
AGL Resources	5.0%	6.0%	5.0%	9.8%	2.8%	5.3%	5.8%	10.8%
Atmos Energy	5.0%	2.7%	3.5%	6.0%	3.3%	5.0%	4.1%	9.1%
Laclede Group	3.6%	3.7%	5.0%	5.0%	4.2%	3.5%	4.3%	7.8%
NICOR	4.5%	3.3%	4.3%	1.2%	3.3%	4.3%	3.3%	7.7%
Northwest Natural Gas	3.3%	3.9%	5.0%	4.0%	5.3%	4.8%	4.6%	7.9%
Piedmont Natural Gas	3.9%	3.3%	4.3%	5.7%	5.0%	5.8%	4.8%	8.7%
South Jersey Industries	3.1%	6.8%	8.3%	9.8%	5.0%	6.7%	7.3%	10.4%
Southwest Gas	3.1%	3.6%	5.0%	3.2%	5.2%	6.0%	4.6%	7.7%
WGL Holdings	4.3%	4.3%	4.3%	3.3%	3.7%	4.0%	3.9%	8.2%
Mean	4.0%	4.2%	5.0%	5.3%	4.2%	5.0%	4.7%	8.7%
Median	3.9%	3.7%	5.0%	5.0%	4.2%	5.0%	4.6%	8.2%
Composite - Mean		8.2%	9.0%	9.3%	8.2%	9.0%	8.7%	
Composite - Median		7.6%	8.9%	8.9%	8.1%	8.9%	8.5%	

Sources: Prior pages of this schedule.

**STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS**

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		\$79.07			
1978	\$12.33	\$85.35	15.00%	7.90%	7.10%
1979	\$14.86	\$94.27	16.55%	8.86%	7.69%
1980	\$14.82	\$102.48	15.06%	9.97%	5.09%
1981	\$15.36	\$109.43	14.50%	11.55%	2.95%
1982	\$12.64	\$112.46	11.39%	13.50%	-2.11%
1983	\$14.03	\$116.93	12.23%	10.38%	1.85%
1984	\$16.64	\$122.47	13.90%	11.74%	2.16%
1985	\$14.61	\$125.20	11.80%	11.25%	0.55%
1986	\$14.48	\$126.82	11.49%	8.98%	2.51%
1987	\$17.50	\$134.04	13.42%	7.92%	5.50%
1988	\$23.75	\$141.32	17.25%	8.97%	8.28%
1989	\$22.87	\$147.26	15.85%	8.81%	7.04%
1990	\$21.73	\$153.01	14.47%	8.19%	6.28%
1991	\$16.29	\$158.85	10.45%	8.22%	2.23%
1992	\$19.09	\$149.74	12.37%	7.29%	5.08%
1993	\$21.89	\$180.88	13.24%	7.17%	6.07%
1994	\$30.60	\$193.06	16.37%	6.59%	9.78%
1995	\$33.96	\$215.51	16.62%	7.60%	9.02%
1996	\$38.73	\$237.08	17.11%	6.18%	10.93%
1997	\$39.72	\$249.52	16.33%	6.64%	9.69%
1998	\$37.71	\$266.40	14.62%	5.83%	8.79%
1999	\$48.17	\$290.68	17.29%	5.57%	11.72%
2000	\$50.00	\$325.80	16.22%	6.50%	9.72%
2001	\$24.69	\$338.37	7.43%	5.53%	1.90%
2002	\$27.59	\$321.72	8.36%	5.59%	2.77%
2003	\$48.73	\$367.17	14.15%	4.80%	9.35%
2004	\$58.55	\$414.75	14.98%	5.02%	9.96%
2005	\$69.93	\$453.06	16.12%	4.69%	11.43%
2006	\$81.51	\$504.39	17.03%	4.68%	12.35%
2007	\$66.17	\$529.59	12.80%	4.86%	7.94%
Average					6.45%

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

**COMPARISON COMPANIES
CAPM COST RATES**

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Proxy Group				
AGL Resources	4.63%	0.85	5.90%	9.6%
Atmos Energy	4.63%	0.80	5.90%	9.4%
Laclede Group	4.63%	0.80	5.90%	9.4%
NICOR	4.63%	0.90	5.90%	9.9%
Northwest Natural Gas	4.63%	0.75	5.90%	9.1%
Piedmont Natural Gas	4.63%	0.80	5.90%	9.4%
South Jersey Industries	4.63%	0.80	5.90%	9.4%
Southwest Gas	4.63%	0.80	5.90%	9.4%
WGL Holdings	4.63%	0.85	5.90%	9.6%
Mean				9.4%
Median				9.4%

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	1992-2001 Average	2003-2007 Average	2008	2009	2011-13
Proxy Group																					
AGL Resources	11.6%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	12.8%	11.8%	13.8%	12.5%	12.5%	14.0%
Atmos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	11.4%	9.7%	8.5%	8.5%	9.5%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	11.3%	11.8%	12.0%	11.0%	11.5%
NICOR	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	13.0%	16.0%	13.8%	16.2%	13.6%	11.5%	12.0%	14.0%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.8%	12.4%	10.5%	10.4%	11.5%	11.5%	11.0%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	11.0%	11.8%	13.0%	11.8%	12.5%	12.5%	13.0%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	13.3%	12.2%	14.0%	14.5%	15.0%	16.5%
Southwest Gas	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.5%	9.7%	8.8%	5.6%	8.0%	8.5%	8.5%	9.5%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.4%	12.0%	12.0%	11.5%	10.5%
Average	10.8%	11.9%	11.3%	10.9%	12.5%	12.4%	11.8%	10.7%	11.6%	12.2%	10.8%	11.8%	11.4%	11.1%	12.5%	11.7%	11.6%	11.7%	11.5%	11.4%	12.2%
Median	11.8%	12.7%	11.6%	12.2%	13.2%	12.7%	11.3%	10.1%	11.2%	11.9%	10.3%	12.2%	11.9%	11.6%	11.0%	12.0%	11.9%	11.7%	12.0%	11.5%	11.5%

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	1992-2001 Average	2003-2007 Average
<i>Proxy Group</i>																		
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	188.0%	179%	187%
Atmos Energy	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	136.0%	202%	145%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	168.0%	166%	176%
NICOR	179%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	234%	230.0%	219%	218%
Northwest Natural Gas	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	208.0%	155%	171%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	210.0%	199%	212%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	231.0%	175%	205%
Southwest Gas	81%	100%	103%	103%	121%	129%	139%	147%	120%	127%	123%	118%	127%	135%	161%	149.0%	117%	138%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	172.0%	180%	172%
Average	158%	183%	165%	162%	179%	193%	200%	183%	169%	177%	162%	167%	176%	184%	187%	188%	177%	180%
Median	162%	189%	169%	164%	178%	183%	197%	176%	168%	177%	152%	169%	179%	183%	184%	188%	176%	181%

Source: Calculations made from data contained in Value Line Investment Survey.

**STANDARD & POOR'S 500 COMPOSITE
RETURNS AND MARKET-TO-BOOK RATIOS
1992 - 2007**

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
Averages:		
1992-2001	14.7%	341%
2003-2007	15.0%	282%

Source: Standard & Poor's Analyst's Handbook, 2008 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Proxy Group	2.0	0.82	A-	A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

**EQUITABLE GAS COMPANY
PRE-TAX COVERAGE**

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Long-Term Debt	43.35%	6.39%	2.77%	2.77%	
Short-Term Debt	9.65%	3.26%	0.31%	0.31%	
Common Equity	47.00%	9.30%	4.37%	7.29%	
Total	100.00%		7.45%	10.37%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage = **3.36**
(10.37% / (2.77% + 0.31%))

Standard & Poor's Utility Benchmark Ratios:
Business Profile of "4"

	A	BBB
Pre-tax coverage	3.3x - 4.0x	2.2x - 3.0x
Total debt to total capital	45%-52%	52%-62%

11/19/08

HBC PD

295

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,

v.

Equitable Gas Company

Docket No. R-2008-2029325, et al

Independent Oil and Gas Association of
Pennsylvania

v.

Equitable Gas Company

C-20066800

SCHEDULES TO THE
SURREBUTTAL TESTIMONY OF
LAFAYETTE K. MORGAN, JR.

REVISED

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

RECEIVED
2008 DEC 11 PM 1:30
SECRETARY'S BUREAU

NOVEMBER 18, 2008

EXETER

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

EQUITABLE GAS COMPANY

Summary of Operating Income
For the Test Year Ended December 31, 2008

	PAPUC Jurisdictional Amount per Co.	OCA Cost of Service Adjustments	Amount After Adjustments	OCA Recommended Change In Revenue	After Proposed 1/ Revenue Change
<u>Operating Revenues</u>					
Total Operating Revenues	\$ 516,617,530	\$ 22,790,905	\$539,408,435	\$ 2,442,441	\$ 541,850,876
<u>Operating Expenses</u>					
Purchased Gas Costs	\$ 359,315,773	\$ -	\$359,315,773	\$ -	\$ 359,315,773
Non-purchased Gas Costs	105,108,151	(9,823,304)	95,284,847	51,686	95,336,533
Depreciation & Amortization Expenses	23,471,055	(74,118)	23,396,937	-	23,396,937
Taxes Other Than Income	2,185,866	-	2,185,866	6,731	2,192,597
Current Federal Income Tax	(3,182,873)	10,037,948	6,855,075	238,164	7,093,239
Current State Income Tax	(1,009,313)	3,183,109	2,173,796	751,051	2,924,847
Deferred Federal Income Taxes	8,545,747	-	8,545,747	-	8,545,747
Investment Tax Credit	(5,529)	-	(5,529)	-	(5,529)
Total Operating Expenses	\$ 494,428,877	\$ 3,323,635	\$497,752,512	\$ 1,047,632	\$ 498,800,144
Net Operating Income	\$ 22,188,653	\$ 19,467,270	\$ 41,655,923	\$ 1,394,809	\$ 43,050,732
Rate Base	\$ 583,252,590		\$577,863,164		\$ 577,863,164
Return On Rate Base	3.80%		7.21%		7.45%

Notes:

1/ This summary schedule reflects the adjustments related to universal service costs and negotiated rate discounts.

EQUITABLE GAS COMPANY

Summary of Revenue Increase at OCA Rate of Return
For the Test Year Ended December 31, 2008

		<u>Amount</u>	<u>Source</u>
Adjusted Rate Base		\$ 577,863,164	Schedule LKM-2, Page 2
Required Rate of Return		<u>7.450%</u>	
Net Operating Income Required		\$ 43,050,806	
Net Operating Income at Present Rates		<u>41,655,923</u>	Schedule LKM-1, Page 1
Income Deficiency/(Surplus)		\$ 1,394,883	
Revenue Multiplier		<u>1.751</u>	
Required Change in Company Revenue		<u>\$ 2,442,441</u>	
Proposed Revenue Change		\$ 2,442,441	
Uncollectibles	1.920%	46,895	
PUC, OCA, OSBA Assessments	0.281%	6,731	
LIURP	0.200%	<u>4,791</u>	
Subtotal		\$ 2,384,024	
State Income Tax	9.99%	<u>238,164</u>	
Subtotal		\$ 2,145,860	
Federal Income Tax	35.00%	<u>751,051</u>	
Net Income Increase Required		<u>\$ 1,394,809</u>	

EQUITABLE GAS COMPANY

Summary of Rate Base
For the Test Year Ended December 31, 2008

	PAPUC Jurisdictional Amount per Co.	OCA Rate Base Adjustments	Amount After Adjustments
Total Plant in Service	\$ 897,954,727	\$ (1,761,627)	\$ 896,193,100
Accumulated Depreciation	(289,353,072)	-	(289,353,072)
Net Plant in Service	\$ 608,601,655	\$ (1,761,627)	\$ 606,840,028
<u>Additions:</u>			
Materials & Supplies	\$ 887,426	\$ -	\$ 887,426
Current Gas Storage	75,175,769	-	75,175,769
Cash Working Capital	11,335,335	(3,627,799)	7,707,536
Prepayments	234,270	-	234,270
Total Additions	\$ 87,632,800	\$ (3,627,799)	\$ 84,005,001
<u>Deductions:</u>			
Accumulated Deferred Income Taxes	\$(104,709,261)	\$ -	\$(104,709,261)
Income Tax Credits	(4,902,910)	-	(4,902,910)
Customer Advances	-	-	-
Customer Deposits	(3,369,694)	-	(3,369,694)
Total Deductions	\$(112,981,865)	\$ -	\$(112,981,865)
Total Rate Base	<u>\$ 583,252,590</u>	<u>\$ (5,389,426)</u>	<u>\$ 577,863,164</u>

EQUITABLE GAS COMPANY

Summary of Rate Base Adjustments
For the Test Year Ended December 31, 2008

	<u>Source</u>	<u>PAPUC Jurisdictional Amount per Co.</u>
Rate Base per Company Filing	Schedule LKM-2, Page 1	<u>\$ 583,252,590</u>
<u>OCA Adjustments:</u>		
Plant in Service	Schedule LKM-5	\$ (1,761,627)
Cash Working Capital	Schedule LKM-6	<u>(3,627,799)</u>
Total Ratemaking Adjustments		<u>\$ (5,389,426)</u>
Adjusted Rate Base per OCA		<u><u>\$ 577,863,164</u></u>

EQUITABLE GAS COMPANY

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Net Income per Company	<u>\$ 22,188,653</u>
<u>OCA Adjustments:</u>	
Annualize Operating Revenues	\$ 13,334,161
Reverse Company's Collection Cost Adjustment	358,178
Remove Excess Anode Expenses	157,767
Normalize Customer Experience Study Costs	372,503
Annualize PA One Call Expense	18,060
Remove Lobbying Expenses	927
Annualize Payroll Expenses	79,818
Reflect Ongoing Level of Pension & OPEB Costs	271,162
Normalize Regulatory Commission Expenses	174,806
Annualize the Increase in Cost of Fuel	40,734
Normalize Injuries & Damages Expense	757,972
Normalize Right of Way Mowing Expense	198,811
Reverse Cathodic Protection Costs	78,120
Universal Service Costs per OCA	3,238,414
Interest Synchronization	342,473
Depreciation Expense	<u>43,364</u>
Total Ratemaking Adjustments	<u>\$ 19,467,270</u>
Total Adjusted Net Income per OCA	<u><u>\$ 41,655,923</u></u>

EQUITABLE GAS COMPANY

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2008

	Operating Revenues	O&M Expenses	Depreciation & Amortization Expenses	Taxes Other Than Income	Current State Income Tax	Current Federal Income Taxes	Deferred Income Taxes	Investment Tax Credit	Net Operating Income
PA Jurisdictional Amount per Company	\$ 516,617,530	\$464,423,924	\$ 23,471,055	\$ 2,185,866	\$ (1,009,313)	\$ (3,182,873)	\$ 8,545,747	\$ (5,529)	\$ 22,188,653
<u>OCA Adjustments:</u>									
Annualize Operating Revenues	\$ 22,790,905	\$ -	\$ -	\$ -	\$ 2,276,811	\$ 7,179,933	\$ -	\$ -	\$ 13,334,161
Reverse Company's Collection Cost Adjustment	-	(612,202)	-	-	61,159	192,865	-	-	358,178
Remove Excess Anode Expenses	-	(269,658)	-	-	26,939	84,952	-	-	157,767
Normalize Customer Experience Study Costs	-	(636,686)	-	-	63,605	200,578	-	-	372,503
Annualize PA One Call Expense	-	(30,868)	-	-	3,084	9,724	-	-	18,060
Remove Lobbying Expenses	-	(1,584)	-	-	158	499	-	-	927
Annualize Payroll Expenses	-	(136,426)	-	-	13,629	42,979	-	-	79,818
Reflect Ongoing Level of Pension & OPEB Costs	-	(463,473)	-	-	46,301	146,010	-	-	271,162
Normalize Regulatory Commission Expenses	-	(298,781)	-	-	29,848	94,127	-	-	174,806
Annualize the Increase in Cost of Fuel	-	(69,623)	-	-	6,955	21,934	-	-	40,734
Normalize Injuries & Damages Expense	-	(1,295,534)	-	-	129,424	408,138	-	-	757,972
Normalize Right of Way Mowing Expense	-	(339,810)	-	-	33,947	107,052	-	-	198,811
Reverse Cathodic Protection Costs	-	(133,524)	-	-	13,339	42,065	-	-	78,120
Universal Service Costs per OCA	-	(5,535,135)	-	-	552,960	1,743,761	-	-	3,238,414
Interest Synchronization	-	-	-	-	(82,454)	(260,019)	-	-	342,473
Depreciation Expense	-	-	(74,118)	-	7,404	23,350	-	-	43,364
Total Rate-making Adjustments	\$ 22,790,905	\$ (9,823,304)	\$ (74,118)	\$ -	\$ 3,183,109	\$ 10,037,948	\$ -	\$ -	\$ 19,467,270
Total Adjusted Income	\$ 539,408,435	\$454,600,620	\$ 23,396,937	\$ 2,185,866	\$ 2,173,796	\$ 6,855,075	\$ 8,545,747	\$ (5,529)	\$ 41,655,923

EQUITABLE GAS COMPANY

Reconciliation of Current State and Federal Income Taxes
For the Test Year Ended December 31, 2008

	Test Year Per Company	Ratemaking Adjustments	Test Year at Present Rates	Increase at OCA Rate of Return	After Proposed Revenue Change
CALCULATION OF COMBINED CURRENT INCOME TAX					
Net Operating Income Before Income Taxes	\$ 26,536,685	\$ 32,688,327	\$ 59,225,012	\$ 2,384,024	\$ 61,609,036
<u>Adjustments for Income Taxes</u>					
Interest Expense	(16,972,820)	(825,365)	(17,798,185)	-	(17,798,185)
Book Depreciation Expense	23,471,055	-	23,471,055	-	23,471,055
Tax Depreciation Expense	(43,138,325)	-	(43,138,325)	-	(43,138,325)
State Taxable Income	<u>\$ (10,103,405)</u>	<u>\$ 31,862,962</u>	<u>\$ (19,667,270)</u>	<u>\$ 2,384,024</u>	<u>\$ (19,667,270)</u>
State Income Tax	9.99% <u>\$ (1,009,330)</u>	<u>\$ 3,183,110</u>	<u>\$ (1,964,760)</u>	<u>\$ 238,164</u>	<u>\$ (1,964,760)</u>
Federal Taxable Income Before State Income Tax	<u>\$ (10,103,405)</u>	<u>\$ 31,862,962</u>	<u>\$ 21,759,557</u>	<u>\$ 2,384,024</u>	<u>\$ 24,143,581</u>
State Income Tax	<u>(1,009,330)</u>	<u>3,183,110</u>	<u>2,173,780</u>	<u>238,164</u>	<u>2,411,944</u>
Federal Taxable Income	<u>\$ (9,094,075)</u>	<u>\$ 28,679,852</u>	<u>\$ 19,585,777</u>	<u>\$ 2,145,860</u>	<u>\$ 21,731,637</u>
Federal Income Tax	35.00% <u>(3,182,926)</u>	<u>10,037,948</u>	<u>6,855,022</u>	<u>751,051</u>	<u>7,606,073</u>
Federal Tax Credits	<u>(5,529)</u>	<u>-</u>	<u>(5,529)</u>	<u>-</u>	<u>(5,529)</u>
Net Federal Income Tax	<u>\$ (3,188,455)</u>	<u>\$ 10,037,948</u>	<u>\$ 6,849,493</u>	<u>\$ 751,051</u>	<u>\$ 7,600,544</u>
Net Combined Current Income Tax	<u>\$ (4,197,785)</u>	<u>\$ 13,221,058</u>	<u>\$ 9,023,273</u>	<u>\$ 989,215</u>	<u>\$ 10,012,488</u>
Total Combined Current Income Taxes (Schedule LKM-1, Page 1)	<u>(4,197,715)</u>	<u>13,221,057</u>	<u>9,023,342</u>	<u>989,215</u>	<u>10,012,557</u>
Unreconciled/Rounding	<u>\$ (70)</u>	<u>\$ 1</u>	<u>\$ (69)</u>	<u>\$ (0)</u>	<u>\$ (69)</u>

EQUITABLE GAS COMPANY

Adjustment to Plant in Service
For the Test Year Ended December 31, 2008

	<u>Amount</u>
<u>Post-Test Year plant in Service</u>	
Purchase New Meters and Regulators	\$ 636,394 1/
Tools and Equipment	242,451 1/
PC and Laptop Replacement	141,000 1/
Automotive Replacements	<u>741,782 1/</u>
Total Adjustment to Plant in Service	<u><u>\$ 1,761,627</u></u>

Notes:

1/ Response to OCA IV-26.

EQUITABLE GAS COMPANY

Adjustment to Allowance for Cash Working Capital
For the Test Year Ended December 31, 2008

	<u>Pro Forma</u> <u>Expenses</u>	<u>OCA</u> <u>Adjustments</u>	<u>Adjusted Pro</u> <u>Forma</u> <u>Expenses</u>	<u>Daily</u> <u>Requirement</u>	<u>Revenue</u> <u>Lag Days</u>	<u>Expense</u> <u>Lag days</u>	<u>Net Lag</u> <u>Days</u>	<u>Working Capital</u> <u>Requirement</u>
	1/				1/	1/		
<u>Operating Expense</u>								
Purchased Gas	\$ 359,315,773	\$ -	\$ 359,315,773	\$ 984,427	49.29	45.91	3.38	\$ 3,327,363
Payroll	24,095,087	(104,967)	23,990,120	65,726	49.29	45.91 2/	3.38	222,168
Employee Benefits	7,069,423	(487,017)	6,582,406	18,034	49.29	17.17	32.12	579,200
Corporate Services	15,990,000	-	15,990,000	43,808	49.29	37.32	11.97	524,408
Injuries & Damages	4,803,788	(1,295,534)	3,508,254	9,612	49.29	(164.74)	214.03	2,057,256
Uncollectibles	25,049,825	46,895	25,096,720	68,758	49.29	49.29	-	-
Other O&M Expenses	28,100,026	(2,387,945)	25,712,081	70,444	49.29	35.49	13.80	971,811
	<u>\$ 464,423,922</u>		<u>\$ 460,195,354</u>					
Depreciation & Amortization	23,471,055	(74,118)	23,396,937	-				-
Taxes Other Than Income	2,185,866	(1,184)	2,184,682	5,985	49.29	(66.05) 3/	115.34	690,339
<u>Income Taxes</u>								
Current Federal	(3,182,873)	10,276,112	7,093,239	19,434	49.29	36.50	12.79	248,555
Current State	(1,009,313)	3,934,160	2,924,847	8,013	49.29	51.58	(2.29)	(18,350)
Deferred Federal & State	8,545,747	-	8,545,747	-				-
Investment Tax Credit	(5,529)	-	(5,529)	-				-
Interest on Debt	16,972,650	825,535	17,798,185	48,762	49.29	72.58	(23.29)	(1,135,670)
Sales and Use Taxes	6,287,006	-	6,287,006	17,225	49.29	35.33	13.96	240,456
Cash Working Capital per OCA								\$ 7,707,536
Cash Working Capital per Company								<u>11,335,335</u>
Adjustment to Cash Working Capital								<u>\$ (3,627,799)</u>

Notes:

- 1/ Exhibit VI, Item 18, page 2.
2/ Schedule LKM-5, page 3.
3/ Schedule LKM-5, page 10.

EQUITABLE GAS COMPANY

Calculation of Non-Union Payroll Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	1/ Lag Days	1/ Amount	1/ Dollar Days
12/18/06	12/31/06	12/24/06	01/10/07	16.50	\$ 663,113	\$ 10,941,365
01/01/07	01/14/07	01/07/07	01/24/07	16.50	663,604	10,949,466
01/01/06	12/31/06 2/	07/02/06	02/06/07	219.00	3,650,116 2/	799,375,404
01/15/07	01/28/07	01/21/07	02/07/07	16.50	665,254	10,976,691
01/29/07	02/11/07	02/04/07	02/21/07	16.50	656,666	10,834,989
02/12/07	02/25/07	02/18/07	03/07/07	16.50	650,454	10,732,491
02/26/07	03/11/07	03/04/07	03/21/07	16.50	682,704	11,264,616
03/12/07	03/25/07	03/18/07	04/04/07	16.50	658,826	10,870,629
03/26/07	04/08/07	04/01/07	04/18/07	16.50	657,239	10,844,444
04/09/07	04/22/07	04/15/07	05/02/07	16.50	663,850	10,953,525
04/23/07	05/06/07	04/29/07	05/16/07	16.50	669,857	11,052,641
05/07/07	05/20/07	05/13/07	05/30/07	16.50	664,132	10,958,178
05/21/07	06/03/07	05/27/07	06/13/07	16.50	666,519	10,997,564
06/04/07	06/17/07	06/10/07	06/27/07	16.50	663,067	10,940,606
06/18/07	07/01/07	06/24/07	07/11/07	16.50	664,892	10,970,718
07/02/07	07/15/07	07/08/07	07/25/07	16.50	662,533	10,931,795
07/16/07	07/29/07	07/22/07	08/08/07	16.50	649,673	10,719,605
07/30/07	08/12/07	08/05/07	08/22/07	16.50	648,531	10,700,762
08/13/07	08/26/07	08/19/07	09/05/07	16.50	635,798	10,490,667
08/27/07	09/09/07	09/02/07	09/19/07	16.50	640,692	10,571,418
09/10/07	09/23/07	09/16/07	10/03/07	16.50	591,651	9,762,242
09/24/07	10/07/07	09/30/07	10/17/07	16.50	593,444	9,791,826
10/08/07	10/21/07	10/14/07	10/31/07	16.50	596,533	9,842,795
10/22/07	11/04/07	10/28/07	11/14/07	16.50	598,294	9,871,851
11/05/07	11/18/07	11/11/07	11/28/07	16.50	590,987	9,751,286
11/19/07	12/02/07	11/25/07	12/12/07	16.50	629,265	10,382,873
12/03/07	12/16/07	12/09/07	12/26/07	16.50	589,239	9,722,444
				<u>52.79</u>	<u>\$ 20,366,933</u>	<u>\$ 1,075,202,885</u>

Notes:

1/ Exhibit VI, Item 18, page 11.

2/ Company response to OTS-RE-18-D.

EQUITABLE GAS COMPANY

Calculation of Union Payroll Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	Mid Point of Service Period	1/ Payment Date	1/ Lag Days	1/ Amount	1/ Dollar Days
12/18/06	12/31/06	12/24/06	01/12/07	18.50	\$ 393,762	\$ 7,284,597
01/01/07	01/14/07	01/07/07	01/26/07	18.50	386,120	7,143,220
01/01/06	12/31/06 2/	07/02/06	02/06/07	219.00	656,326	143,735,394
01/15/07	01/28/07	01/21/07	02/09/07	18.50	369,857	6,842,355
01/29/07	02/11/07	02/04/07	02/23/07	18.50	374,081	6,920,499
02/12/07	02/25/07	02/18/07	03/09/07	18.50	387,408	7,167,048
02/26/07	03/11/07	03/04/07	03/23/07	18.50	373,400	6,907,900
03/12/07	03/25/07	03/18/07	04/04/07	16.50	330,927	5,460,296
03/26/07	04/08/07	04/01/07	04/20/07	18.50	351,323	6,499,476
04/09/07	04/22/07	04/15/07	05/04/07	18.50	347,062	6,420,647
04/23/07	05/06/07	04/29/07	05/18/07	18.50	334,124	6,181,294
05/07/07	05/20/07	05/13/07	06/01/07	18.50	336,230	6,220,255
05/21/07	06/03/07	05/27/07	06/15/07	18.50	353,260	6,535,310
06/04/07	06/17/07	06/10/07	06/29/07	18.50	337,679	6,247,062
06/18/07	07/01/07	06/24/07	07/13/07	18.50	341,521	6,318,139
07/02/07	07/15/07	07/08/07	07/27/07	18.50	345,752	6,396,412
07/16/07	07/29/07	07/22/07	08/10/07	18.50	333,438	6,168,603
07/30/07	08/12/07	08/05/07	08/24/07	18.50	347,811	6,434,504
08/13/07	08/26/07	08/19/07	09/07/07	18.50	337,253	6,239,181
08/27/07	09/09/07	09/02/07	09/21/07	18.50	335,121	6,199,739
09/10/07	09/23/07	09/16/07	10/05/07	18.50	331,445	6,131,733
09/24/07	10/07/07	09/30/07	10/19/07	18.50	352,580	6,522,730
10/08/07	10/21/07	10/14/07	11/02/07	18.50	355,828	6,582,818
10/22/07	11/04/07	10/28/07	11/16/07	18.50	355,294	6,572,939
11/05/07	11/18/07	11/11/07	11/30/07	18.50	375,779	6,951,912
11/19/07	12/02/07	11/25/07	12/14/07	18.50	395,601	7,318,619
12/03/07	12/16/07	12/09/07	12/28/07	18.50	351,392	6,500,752
				<u>31.74</u>	<u>\$ 9,890,374</u>	<u>\$ 313,903,428</u>
Combined Payroll Amounts				<u>45.91</u>	<u>\$ 30,257,307</u>	<u>\$ 1,389,106,313</u>

Notes:

1/ Exhibit VI, Item 18, page 12.

EQUITABLE GAS COMPANY

Calculation of Corporate Services Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	Mid Point of Service Period	1/ Payment Date	Lag Days	2/ Amount	Dollar Days
01/01/07	01/31/07	01/16/07	02/15/07	30.00	\$ 1,311,496	\$ 39,344,880
02/01/07	02/28/07	02/14/07	03/27/07	40.50	1,354,246	54,846,963
03/01/07	03/31/07	03/16/07	04/19/07	34.00	1,354,246	46,044,364
04/01/07	04/30/07	04/15/07	05/15/07	29.50	1,354,246	39,950,257
05/01/07	05/31/07	05/16/07	06/20/07	35.00	1,354,246	47,398,610
06/01/07	06/30/07	06/15/07	07/24/07	38.50	1,267,733	48,807,721
07/01/07	07/31/07	07/16/07	08/21/07	36.00	1,354,246	48,752,856
08/01/07	08/31/07	08/16/07	09/18/07	33.00	1,354,246	44,690,118
09/01/07	09/30/07	09/15/07	10/18/07	32.50	1,331,410	43,270,825
10/01/07	10/31/07	10/16/07	11/20/07	35.00	1,354,246	47,398,610
11/01/07	11/30/07	11/15/07	12/20/07	34.50	1,354,246	46,721,487
12/01/07	12/31/07	12/16/07	02/21/08	67.00	1,449,883	97,142,161
				37.32	\$ 16,194,490	\$ 604,368,852

Notes:

1/ Exhibit VI, Item 18, page 13.

2/ Company response to OCA XV-1.

EQUITABLE GAS COMPANY

Calculation of Other O&M-Goods & Services Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u>	<u>Amount</u> 1/	<u>Dollar Days</u> 1/
Other O&M Totals		\$ 3,568,382	\$ 100,655,431
Other Goods & Services Totals		11,640,164	399,128,278
OSS - NCO Totals		2,794,637	151,981,995
OSS - Trafford Totals		1,741,825	79,604,796
OSS - HEATH Consultants Totals		1,192,201	44,544,821
C. Leon Sherman & Associates		498,255	20,827,565
Pittsburgh Mailing & ADS		848,033	24,098,883
Retiree Benefits		<u>3,446,372</u>	<u>92,426,848</u>
Other O&M Totals		<u>\$ 25,729,869</u>	<u>\$ 913,268,617</u>
Other O&M Lag Days	<u>35.49</u>		

Notes:

1/ Exhibit VI, Item 18, pages 14 - 18.

2/ Schedule LKM-6, Page 6.

EQUITABLE GAS COMPANY

Calculation of Other O&M-C. Leon Sherman Lag
For the Test Year Ended December 31, 2008

Payroll Period Begin	1/ Payroll Period End	1/ Mid Point of Service Period	1/ Payment Date	1/ Lag Days	1/ Amount	1/ Dollar Days
12/01/06	12/31/06	12/16/06	01/30/07	45.00	\$ 87,651	\$ 3,944,295
01/01/07	01/31/07	01/16/07	03/01/07	44.00	76,761	3,377,484
02/01/07	02/28/07	02/14/07	03/20/07	33.50	57,826	1,937,171
04/01/07	04/30/07	04/15/07	05/22/07	36.50	155,913	5,690,825
05/01/07	05/31/07	05/16/07	06/28/07	43.00	15,191	653,213
06/01/07	06/30/07	06/15/07	07/24/07 2/	38.50	7,479	287,942
07/01/07	07/31/07	07/16/07	08/28/07	43.00	24,015	1,032,645
09/01/07	09/30/07	09/15/07	10/04/07	18.50	9,285	171,773
09/01/07	09/30/07	09/15/07	11/13/07	58.50	24,893	1,456,241
10/01/07	10/31/07	10/16/07	12/13/07	58.00	39,241	2,275,978
				<u>41.80</u>	<u>\$ 498,255</u>	<u>\$ 20,827,565</u>

Notes:

1/ Exhibit VI, Item 18, pages 15 - 18.

2/ Response to OTS-RE-23-D.

EQUITABLE GAS COMPANY

Calculation of Pensions & Benefits Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u> 1/	<u>Amount</u> 1/	<u>Dollar Days</u>
Total 401(k) Match & Retirement Contribution		\$ 1,944,377 2/	\$ 32,082,219
Total 401(k) Administration Fees		1,398	127,849
Total ESPP Discount		26,607	557,948
Total ESPP Administration Fees		15,813	1,821,280
Total HSA Company Contribution		162,250	(28,356,500)
Total HSA Account Fees		8,232	72,322
Total Health Claims, Admin & Enrollment Fees		2,736,530	24,628,772
Total Active Vision		61,489	2,435,075
Total Executive Health Care Exams		9,225 3/	-
Total Active Life, AD&D, LTD		182,935	7,197,330
Total Active Dental		242,987	7,766,042
Total Employee Assistance Program		14,770	140,129
Total Aon Admin Fees		148,394	13,680,486
Retirees Pensions & Benefits Totals		3,446,372	92,426,848
Pension & Benefit Totals		<u>\$ 9,001,379</u>	<u>\$ 154,579,800</u>
Pension & Benefits Lag Days	<u>17.17</u>		

Notes:

1/ Exhibit VI, Item 18, pages 20 - 27.

2/ Schedule LKM-6, page 8.

3/ Schedule LKM-6, Page 9.

EQUITABLE GAS COMPANY

Calculation of 401(k) Match & Retirement Contribution Lag
For the Test Year Ended December 31, 2008

	<u>Payroll Period Begin</u>	<u>Payroll Period End</u>	<u>Mid Point of Service Period</u>	<u>Payment Date</u>	<u>Lag Days</u>	<u>Amount</u>	<u>Dollar Days</u>
<u>401(k) Match & Retirement Contribution</u>							
Total Per Company						\$ 1,945,742 1/	\$ 32,104,741 1/
Bonus Contribution per Co.	01/14/07 1/	01/27/07 1/	01/20/07 1/	02/06/07 1/	16.50 1/	(1,365) 1/	(22,523) 1/
Bonus Contribution per OCA	01/01/06	12/31/06	07/02/06	02/06/07	219.00 2/	-	-
Total 401(k) Match & Retirement Contribution Per OCA					16.50	<u>1,944,377</u>	<u>32,082,219</u>

Notes:

1/ Exhibit VI, Item 18, page

2/ Based on the response to OTS-RE-18-D.

EQUITABLE GAS COMPANY

Calculation of Executive Health Care Exams Lag
For the Test Year Ended December 31, 2008

<u>Payroll Period Begin</u>	<u>Payroll Period End</u>	<u>Mid Point of Service Period</u>	<u>Payment Date</u> 1/	<u>Lag Days</u>	<u>Amount</u> 1/	<u>Dollar Days</u>
Executive Health Exams						
01/04/07 2/	01/04/07 2/	01/04/07	01/04/07	0.00	\$ 1,825	\$ -
03/06/07 2/	03/06/07 2/	03/06/07	03/06/07	0.00	3,650	-
03/15/07 2/	03/15/07 2/	03/15/07	03/15/07	0.00	1,825	-
08/02/07 2/	08/02/07 2/	08/02/07	08/02/07	0.00	1,925	-
Totals				<u>0.00</u>	<u>\$ 9,225</u>	<u>\$ -</u>

Notes:

1/ Exhibit VI, Item 18, page 23.

2/ Response to OCA I-50.

EQUITABLE GAS COMPANY

Calculation of Taxes Other Than Income Lag
For the Test Year Ended December 31, 2008

	<u>Lag Days</u>	<u>Amount</u>	<u>Dollar Days</u>
Combined Taxes Other Than Income Amounts Per Company		\$ 1,394,466 2/	\$ (92,099,751) 2/
Payroll Taxes	- 1/	- 3/	- 4/
Combined Taxes Other Than Income Amounts	<u>(66.05)</u>	<u>\$ 1,394,466</u>	<u>\$ (92,099,751)</u>

Notes:

1/ Exhibit VI, Item 18, page 12.

2/ Exhibit VI, Item 18, page 31.

3/ Exhibit III, Item § 53.53 III.A.17, Sheet 6.

4/ Lag days x Amount.

EQUITABLE GAS COMPANY

Adjustment to Annualize Operating Revenues
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Annualize Operating Revenues	<u>\$ 22,790,905</u> 1/
Adjustment to Operating Revenues	<u><u>\$ 22,790,905</u></u>

Notes:

1/ Adjustment Recommended by OCA Witness Glen Watkins.

EQUITABLE GAS COMPANY

Adjustment to Reverse Company's Adjustment to Include
Collection Costs in O&M Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Collection Costs Included in the Cost of Service	<u>612,202</u> 1/
Adjustment to O&M Expenses	<u><u>\$ (612,202)</u></u>

Notes:

1/ Exhibit III, Item § 53.53 III.A.17, Page 9.

EQUITABLE GAS COMPANY

Adjustment to Remove Excess Anode Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Excess Anode Expenses	<u>\$ 269,658 1/</u>
Adjustment to O&M Expenses	<u><u>\$ (269,658)</u></u>

Notes:

1/ Response to OCA I-19.

EQUITABLE GAS COMPANY

Adjustment to Normalize Customer Experience Study Costs
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Customer Experience Study Costs	\$ 795,858 1/
Normalization Period (Years)	<u>5</u>
Normalized Customer Experience Study Costs	\$ 159,172
Customer Experience Study Costs per Company	<u>795,858</u>
Adjustment to O&M Expenses	<u><u>\$ (636,686)</u></u>

Notes:

1/ Response to OCA I-26.

EQUITABLE GAS COMPANY

Adjustment to Annualize PA One Call Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>	
Routine Unit Cost	\$ 16.05	1/
Number of Units	<u>32,420</u>	2/
Annual Costs at Contract Rate	\$ 520,341	1/
Increased PA One Call System Charge	<u>20,974</u>	2/
Annulized PA One Call Expense	\$ 541,315	
Annulized PA One Call Expense per Company	<u>572,183</u>	
Adjustment to O&M Expenses	<u><u>\$ (30,868)</u></u>	

Notes:

1/ Response to OCA I-20.

2/ Schedule JCM-6.

EQUITABLE GAS COMPANY

Adjustment to Remove Lobbying Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Lobbying Expenses Included in Corporate Allocation	\$ - 1/
Portion of AGA Dues Attributed to Lobbying	<u>(1,584) 2/</u>
Adjustment to O&M Expenses	<u><u>\$ (1,584)</u></u>

Notes:

1/ Lobbying Expense per Response to OTS-RE-78-D less \$88,378 per Page 13,
Line 15 of Witness Mitchell Rebuttal Testimony.

2/ Exhibit VI, Standard Data Request, Volume 1, Item No.33.

EQUITABLE GAS COMPANY

Adjustment to Annualize Payroll Expenses
For the Test Year Ended December 31, 2008

	<u>Amount</u>
<u>Payroll Expenses</u>	
<u>Unfilled Positions</u>	
Compression Operator	\$ -
Compression Operator	-
Producer Services Analyst	39,967 1/
Producer Services Engineer	65,000 1/
<u>Vacated Positions</u>	
Position # 99909180	-
Adjustment to Payroll Expenses	<u>\$ (104,967)</u>
<u>Fringe Benefits Expenses</u>	
Total Fringe Benefits Percentage	29.97%
Total Decrease in Fringe Benefits Expenses	<u>\$ (31,459)</u>
Adjustment to O&M Expenses	<u><u>\$ (136,426)</u></u>

Notes:

1/ Response to OCA I-11.

EQUITABLE GAS COMPANY

Adjustment to Reflect Pension & Postretirement Benefits at the Ongoing Level
For the Test Year Ended December 31, 2008

	<u>Amount</u>
2008 Total Pension Cost	\$ 594,491 1/
2008 Total Postretirement Benefits Cost	<u>1,807,247 1/</u>
Total Pension & Postretirement Benefits Costs	\$ 2,401,738
Pennsylvania Percentage	<u>98.36% 2/</u>
Pennsylvania Pension & Postretirement Benefits Costs	\$ 2,362,349
O&M Percentage	<u>84.40%</u>
Pennsylvania Pension & Postretirement Benefits Expense	\$ 1,993,823 3/
PA Pension & Postretirement Benefits Expense per Company	<u>2,457,296 4/</u>
Adjustment to O&M Expenses	<u><u>\$ (463,473)</u></u>

Notes:

1/ Response to OTS-RE-68-D.

2/ Standard Data Requests, Item 23.

3/ Standard Data Requests, Item 19.

4/ Response to OTS-RE-139-D.

EQUITABLE GAS COMPANY

Adjustment to Normalize Regulatory Commission Expenses
For the Test Year Ended December 31, 2008

	Amount
Cost of the Current Rate Case	\$ 1,051,160 1/
Cost of the Service Life Study	<u>15,000 2/</u>
Total Rate Case	\$ 1,066,160
Normalization Period (Years)	<u>5</u>
Normalized Rate Case Expenses	\$ 213,232
Historical Test Year Regulatory Expenses	13,474 3/
Costs Related to West Virginia Matters	<u>(8,626) 4/</u>
Future Test Year Regulatory Expenses per OCA	\$ 218,080
Future Test Year Regulatory Expenses per Company	<u>516,861</u>
Adjustment to O&M Expenses	<u><u>\$ (298,781)</u></u>

Notes:

1/ Exhibit III, Item § 53.53 III.A.20 Sheet 2.

2/ Per OTS-RE-89-D, the total cost of the management audit and the service life study is \$765,000, and OCA IV-15 the management audit cost is \$750,000.

3/ Exhibit III, Item § 53.53 III.A.28 Sheet 7.

4/ Per response to OCA IV-8.

EQUITABLE GAS COMPANY

Adjustment to Annualize the Increase in Cost of Fuel
For the Test Year Ended December 31, 2008

	<u>Diesel Gallons</u>		<u>Gasoline Gallons</u>		<u>Totals</u>
January 2008 - August 2008 Fuel Usage	57,247	1/	178,709	1/	
Period Number of Months	8		8		
Annual Number of Months	<u>12</u>		<u>12</u>		
Annualized 2008 Fuel Usage	85,871		268,064		
2008 Price per Gallon	<u>\$ 4.00</u>	2/	<u>\$ 3.61</u>	2/	
Annualized Fuel Expense	\$ 343,482		\$ 967,709		\$ 1,311,191
Annualized Fuel Expense per Company	<u>392,391</u>	2/	<u>988,423</u>	2/	<u>1,380,814</u>
Adjustment to O&M Expenses	<u>\$ (48,909)</u>		<u>\$ (20,714)</u>		<u>\$ (69,623)</u>

Notes:

1/ Response to OCA VIII-18.

2/ Response to OCA I-17.

EQUITABLE GAS COMPANY

Adjustment to Normalize Injuries & Damages Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>	<u>Totals</u>
<u>Charges Against the Reserve (Claims)</u>		
2005 Charges Against the Reserve	\$ 235,769 1/	
2006 Charges Against the Reserve	256,243 1/	
2007 Charges Against the Reserve	<u>363,135 1/</u>	
Average		\$ 285,049
<u>Legal Settlements</u>		
2005 Settlement Expense	\$ 108,750 1/	
2006 Settlement Expense	311,680 1/	
2007 Settlement Expense	<u>3,960,828 1/</u>	
Average		\$ 1,460,419
<u>Test Year Expense</u>		
2007 Expense Accrual	\$ 2,888,475 1/	
2007 Reserve Adjustments	(2,992,765) 1/	
Company's Pro Forma Normalization Adjustment	<u>3,145,292 1/</u>	
Net Injuries & Damages Expense		<u>3,041,002</u>
Adjustment to O&M Expenses		<u><u>\$(1,295,534)</u></u>

Notes:

1/ Response to OCA I-1.

EQUITABLE GAS COMPANY

Adjustment to Normalize Right of Way Mowing Expense
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Revised Right of Way Mowing Expense	\$ 200,100 1/
Right of Way Mowing Expense	<u>539,910 1/</u>
Adjustment to O&M Expenses	<u>\$ (339,810)</u>

Notes:

1/ Witness Mitchell Rebuttal Testimony at Page 27, Lines 6 through 12.

EQUITABLE GAS COMPANY

Adjustment to Reverse Cathodic Protection Costs Related to DOT Compliance
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Cathodic Protection Costs	<u>\$ 133,524 1/</u>
Adjustment to O&M Expenses	<u><u>\$ (133,524)</u></u>

Notes:

1/ Response to OCA 1-4.

EQUITABLE GAS COMPANY

Adjustment to Reflect OCA's Universal Service Costs adjustments
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Total Universal Service Adjustments per OCA	
Witness Colton	\$ 11,170,763 1/
CAP Administrative Costs	<u>168,794 1/</u>
Total Universal Service and Administrative	
Costs per OCA	\$ 11,339,557
Total Universal Service and Administrative	
Costs per Company	<u>16,874,692 2/</u>
Adjustment to O&M Expenses	<u><u>\$ (5,535,135)</u></u>

Notes:

1/ Schedule RDC-2SR.

2/ Schedule RDC-5.

EQUITABLE GAS COMPANY

Interest Synchronization Adjustment
For the Test Year Ended December 31, 2008

	<u>Amount</u>
OCA Rate Base	\$ 577,863,164 1/
Weighted Cost of Debt	<u>3.08%</u>
Adjusted Interest Deduction	\$ 17,798,185
Interest Deduction Per Company	<u>16,972,820 2/</u>
Adjustment to Synchronize Interest Expense	\$ 825,365
Effective State Income Tax Rate	<u>9.99%</u>
Adjustment to State Income Taxes	<u>\$ (82,454)</u>
Federal Income Tax Base	\$742,911
Federal Income Tax Rate	<u>35.00%</u>
Adjustment to Federal Income Taxes	<u>\$ (260,019)</u>

Notes:

1/ Schedule LKM-2, Page 1.

2/ Exhibit III, Item § 53.53 III.A.17, Sheet 8.

EQUITABLE GAS COMPANY

Adjustment to Depreciation Expense Related to Post-Test Plant in Service
For the Test Year Ended December 31, 2008

	<u>Amount</u>
Depreciation Expense Related to Post-Test Year Plant in Service	<u>\$ 74,118 1/</u>
Adjustment to Depreciation Expense	<u><u>\$ (74,118)</u></u>

Notes:

1/ Company Witness Gras.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08

NBC, DL

RJS

Pennsylvania Public Utility Commission,

v.

Equitable Gas Company

Docket No. R-2008-2029325, et al

Independent Oil and Gas Association of
Pennsylvania

v.

Equitable Gas Company

C-20066800

SURREBUTTAL TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

RATE OF RETURN

NOVEMBER 14, 2008

RECEIVED
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1 **INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME AND ADDRESS.**

3 A. My name is David C. Parcell. I am President and Senior Economist of Technical
4 Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond,
5 Virginia 23219.

6 **Q. ARE YOU THE SAME DAVID C. PARCELL WHO FILED DIRECT**
7 **TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN**
8 **THIS PROCEEDING?**

9 A. Yes, I am.

10 **Q. WHAT IS THE PURPOSE OF YOUR CURRENT TESTIMONY?**

11 A. My current testimony is Surrebuttal Testimony in response to the Rebuttal
12 Testimony of Equitable Gas witness Frank J. Hanley.

13 **Q. PLEASE DESCRIBE THE ISSUES RAISED IN MR. HANLEY'S REBUTTAL**
14 **TESTIMONY THAT YOU ARE RESPONDING TO IN THIS SURREBUTTAL**
15 **TESTIMONY.**

16 A. My response to Mr. Hanley's Rebuttal Testimony generally follows the format he
17 utilizes and is organized into the following topics:

- 18 ● Capital structure issues
- 19 ● Trends in capital costs
- 20 ● Discounted Cash Flow Model Issues
- 21 ● Capital Asset Pricing Model Issues
- 22 ● Comparable Earnings Method Issues
- 23 ● Risk Issues

1 **CAPITAL STRUCTURE ISSUES**

2 **Q. ON PAGES 35-36, MR. HANLEY DISAGREES WITH YOUR USE OF A**
3 **HYPOTHETICAL CAPITAL STRUCTURE WITH 47 PERCENT COMMON**
4 **EQUITY, AND MAINTAINS THAT HIS PROPOSED 50 PERCENT**
5 **HYPOTHETICAL EQUITY RATIO IS MORE APPROPRIATE. WHAT IS**
6 **YOUR RESPONSE TO THIS?**

7 A. I disagree with Mr. Hanley. We both use a hypothetical structure for Equitable
8 Gas because the Company has not maintained its own distinct capital structure and the
9 capital structure of its parent (Equitable Resources) is not proper to use for the purpose of
10 determining its cost of capital. As I indicate on page 20 of my direct testimony (OCA
11 Statement No. 2), a 47 percent common equity ratio matches the average common equity
12 ratio of the proxy group which both myself and Mr. Hanley use to estimate the cost of
13 equity for Equitable Gas.

14 Mr. Hanley's position (page 36, lines 2-17) is that Equitable Gas is more risky
15 than the proxy group. As a result, he maintains that Equitable Gas should have a higher
16 equity ratio and a higher cost of equity than the proxy group. I have demonstrated in my
17 direct testimony (pages 45-48) that Equitable Gas is not entitled to any of the risk
18 adjustments proposed by Mr. Hanley. I note that nothing in Mr. Hanley's rebuttal
19 testimony changes my position on this issue. I also note that Office of Trial Staff witness
20 Plonski's testimony reaches the same conclusions on this issue as does my testimony.

21 It is noteworthy that Mr. Hanley is proposing two types of adjustments for
22 Equitable Gas' perceived risk. Even though neither adjustment is proper, clearly it is not
23 proper to make both a capital structure adjustment and a cost of equity adjustment.

1 **Q. MR. HANLEY MAINTAINS (PAGE 36, LINES 18-21, AND PAGE 37, LINES 1-**
2 **18) THAT THE REORGANIZATION OF EQUITABLE RESOURCES, AND**
3 **ESTABLISHMENT OF EQUITABLE GAS AS A SUBSIDIARY, SHOULD HAVE**
4 **NO IMPACT ON THE UTILITY'S COST OF CAPITAL BECAUSE EQUITABLE**
5 **GAS IS A "STAND-ALONE ENTITY." DO YOU AGREE?**

6 **A.** No, I do not. I pointed out on pages 16-17 of my direct testimony that the
7 reorganization should result in a reduction in Equitable Gas' risk for this very reason. I
8 also demonstrated that this effect was acknowledged in the Application For
9 Reorganization that Equitable Gas' risk profile would be reduced because of segregation
10 of utility assets in a separate legal entity structure. I further note that both Moody's and
11 S&P acknowledge that the risk of Equitable Gas is less than that of Equitable Resources.
12 Only Mr. Hanley seems to be in disagreement with this. I further note that Mr. Hanley
13 does not acknowledge any of the above-cited documents in his rebuttal testimony.

14 **TRENDS IN CAPITAL COSTS**

15 **Q. MR. HANLEY DISPUTES (PAGE 38, LINES 6-12) BOTH EXCLUSIVE AND**
16 **PRIMARY RELIANCE ON DCF METHODOLOGY. DO YOU HAVE A**
17 **RESPONSE?**

18 **A.** Mr. Hanley's position has been consistently rejected by the Commission while my
19 analysis is consistent with the Commission's longstanding precedent of primary reliance
20 upon DCF. Additionally, I have performed both a CAPM and CE analysis as a check,
21 which confirms the reasonableness of my DCF analysis.
22

1 Q. MR. HANLEY IS MAINTAINING (PAGES 38-40) THAT CAPITAL COSTS
2 HAVE INCREASED DUE TO THE RECENT AND CURRENT "GLOBAL
3 FINANCIAL CRISIS." WHAT IS YOUR RESPONSE TO THIS ASSERTION?

4 A. Mr. Hanley is essentially stating that, because there is a financial crisis that is
5 threatening to create a significant recession on a global basis, the cost of equity for
6 utilities in general and Equitable Gas in particular should be higher. In doing so, Mr.
7 Hanley is ignoring the following factors:

- 8 • Any recession, and in particular a significant recession, will have the
9 effect of lowering profits and growth rates for competitive firms;
- 10 • A recession will have adverse impacts on the incomes and profits of
11 Equitable Gas' ratepayers, whether residential, small commercial, or
12 industrials;
- 13 • The actions being taken by the U.S. and global governments are
14 specifically designed to restore credit and lower the cost of capital; and,
- 15 • Interest rates and capital costs can be expected to decline during a
16 recession.

17 Yet, Mr. Hanley seems to be suggesting that Equitable Gas be awarded a higher cost of
18 equity. Such an outcome would be completely opposite to the expected impact of a
19 recession. Rather, in an economic climate such as the current one, one would expect to
20 see lower cost of equities awarded to regulated utilities than what has been awarded in
21 the recent past in a different economy.

1 **DISCOUNTED CASH FLOW MODEL (DCF) ISSUES**

2 **Q. ON PAGE 40, LINES 8-10, MR. HANLEY MAINTAINS THAT THE DCF**
3 **MODEL "WILL MATHEMATICALLY MIS-SPECIFY INVESTORS'**
4 **REQUIRED RETURN RATE WHEN THE MARKET VALUE OF COMMON**
5 **STOCK DIFFERS SIGNIFICANTLY FROM ITS BOOK VALUE." DO YOU**
6 **AGREE WITH THIS?**

7 A. No, I do not. If stock markets are efficient, as Mr. Hanley recognized in his
8 Direct Testimony, all relevant information is reflected in stock prices, including the
9 differential between book value and market price for regulated utilities. As a result, there
10 is no justification for "adjusting" stock-priced based models, such as DCF.

11 **Q. ON PAGES 49-50, MR. HANLEY TAKES ISSUE WITH YOUR**
12 **DEMONSTRATION THAT HE HAD NOT MADE A DOWNWARD**
13 **ADJUSTMENT TO DCF COST RATES IN THE 1970s AND EARLY 1980s**
14 **WHEN MARKET-TO-BOOK RATIOS WERE BELOW 100 PERCENT. IS HIS**
15 **EXPLANATION VALID?**

16 A. No, it is not. Mr. Hanley is attempting to obscure the fact that his positions are
17 inconsistent because of his claim that he used multiple methodologies in the earlier time
18 period. This is an invalid reason for changing his methodology. Mr. Hanley uses
19 multiple methodologies in his current testimony but, because his DCF results produce
20 lower results, he now claims that these should be adjusted. The fact is, if he is going to
21 make an upward adjustment to DCF results now because of market-to-book ratios above
22 100 percent, he should have made a downward adjustment when market-to-book ratios
23 were below 100 percent. He did not.

1
2 **CAPITAL ASSET PRICING MODEL (CAPM) ISSUES**

3 **Q. ON PAGE 42, LINES 9-22 AND PAGE 43, LINES 1-5, MR. HANLEY**
4 **DISAGREES WITH YOUR POSITION THAT THE CAPM IS GENERALLY**
5 **SUPERIOR TO THE SIMPLE RISK PREMIUM METHOD. WHAT IS YOUR**
6 **RESPONSE TO THIS?**

7 A. Mr. Hanley disagrees with my position that CAPM specifically recognizes the
8 risk of a particular company or industry, whereas the simple risk premium does not. Mr.
9 Hanley states his opinion that I am "incorrect" in my position. I disagree with him on
10 this point.

11 Mr. Hanley's position apparently focuses on the use of public utility bond yields
12 in his risk premium analysis which he believes properly recognizes the risk of the subject
13 company. This is misleading in terms of its ability to measure risk comparability. It
14 should be noted that Mr. Hanley's risk premium model starts with the prospective yield
15 on Aaa rated corporate bonds. Since Equitable Gas does not have Aaa rated debt, he then
16 computes the historic differential between Aaa rated corporate bonds and A-rated public
17 utility bonds for the period August-September, 2008 (as shown in Equitable Exhibit 5A-
18 R, Schedule 6, page 1 of 3).

19 This procedure makes no allowance for the differences among various types of
20 utilities that are included in the A rated public utility bonds. His procedure assumes that
21 all A-rated public utilities have the same cost of capital. However, he has not offered any
22 evidence that this is the case.

1 In addition, his procedure implicitly assumes that the yield differential of this
2 two-month period reflects the on-going differential in the eyes of investors. Again, he
3 has not offered any evidence that supports this proposition.

4 My CAPM analysis, in contrast, uses a specific measure of risk (i.e., beta) that
5 reflects the relative stock price variability of specific stocks, or groups of similar-risk
6 stocks. As such, the beta component in a CAPM analysis does specifically recognize the
7 risk of the subject company, unlike the risk premium that essentially assigns the same
8 cost of equity for all utilities with the same bond rating.

9 **Q. BUT DOESN'T MR. HANLEY STATE (PAGE 42, LINES 10-13) THAT BETA**
10 **GENERALLY "REFLECTS ON AVERAGE ONLY ABOUT 26% OF**
11 **COMPANY-SPECIFIC RISK"?**

12 **A.** Yes, he does. However, Mr. Hanley fails to recognize that beta typically is used
13 in a CAPM analysis and in cases before this Commission as a risk measure. Mr. Hanley
14 does not offer an opinion as to how much of company-specific risk is captured by the
15 two-month differential between Aaa rated corporate bonds and A-rated public utility
16 bonds.

17 **Q. MR. HANLEY STATES, ON PAGES 16-18 AND 45, THAT IT IS IMPROPER TO**
18 **CONSIDER GEOMETRIC MEAN RETURNS IN THE DETERMINATION OF A**
19 **RISK PREMIUM AND THAT ONLY ARITHMETIC RETURNS ARE**
20 **APPROPRIATE. DO YOU AGREE WITH THIS POSITION?**

21 **A.** No, I do not. What is important is what investors rely upon in making investment
22 decisions. It is apparent that investors have access to both types of returns when they
23 make investment decisions.

1 In fact, it is noteworthy that mutual fund investors regularly receive reports on
2 their own funds, as well as prospective funds they are considering investing in, that show
3 only geometric returns. Based on this, I find it difficult to accept Mr. Hanley's position
4 that only arithmetic returns are appropriate.

5 **Q. DOES MR. HANLEY USE VALUE LINE INFORMATION IN HIS COST OF**
6 **CAPITAL ANALYSES?**

7 A. Yes, he does. He has in fact submitted several Value Line reports on various
8 natural gas utilities in his direct testimony.

9 **Q. DO THE VALUE LINE REPORTS IN HIS EXHIBIT SHOW HISTORIC**
10 **GROWTH RATES FOR THE NATURAL GAS UTILITIES?**

11 A. Yes, they do.

12 **Q. DO THESE VALUE LINE REPORTS SHOW HISTORIC RETURNS ON AN**
13 **ARITHMETIC BASIS?**

14 A. No, they do not.

15 **Q. DO THE VALUE LINE REPORTS SHOW HISTORIC RETURNS ON A**
16 **GEOMETRIC (I.E., COMPOUND) GROWTH RATE BASIS?**

17 A. Yes, they do. As a result, any investor reviewing Value Line, as Mr. Hanley does,
18 *would be using geometric growth rates.*

19 **Q. IS IT YOUR POSITION THAT ONLY GEOMETRIC GROWTH RATES BE**
20 **USED?**

21 A. No. I believe that both arithmetic and geometric growth rates should be used.
22 This is the case since investors have access to both and presumably use both. This is also
23 consistent with the efficient market hypothesis, which Mr. Hanley cites.

1 **Q. DOES MR. HANLEY STATE (PAGES 16-17) HIS PERCEPTION THAT**
2 **“FINANCIAL LITERATURE” REQUIRES THAT ARITHMETIC RETURNS**
3 **BEING USED FOR THIS PURPOSE?**

4 A. He does state this in his testimony. The cost of equity, however, is based on the
5 ongoing inter-play of countless investors, each with their own agendas and beliefs. This
6 is verified by the fact that each time a share of stock is purchased by one investor, it is
7 simultaneously being sold by another investor, indicating that their respective views at
8 that time differ.

9 Again, investors have access to both arithmetic and geometric growth rates. In all
10 likelihood, there is more geometric growth data readily available to investors (e.g.,
11 mutual fund reports and Value Line) than arithmetic growth data.

12 **Q. ON PAGE 45, LINES 17-23, MR. HANLEY CLAIMS TO HAVE**
13 **“RECALCULATED” YOUR CAPM RESULTS. IS THIS A PROPER**
14 **EXERCISE?**

15 A. No, it is not. Mr. Hanley’s “recalculations” are simply his attempt to interject his
16 CAPM components including this improper reliance on the arithmetic mean to the
17 exclusion of the geometric mean, into my CAPM analyses. I have demonstrated both
18 here and in my direct testimony why both should be included in my analysis. Mr.
19 Hanley’s recalculation is incorrect and improper.

20 **Q. MR. HANLEY ALSO CLAIMS, ON PAGES 51-52, THAT YOU HAVE A**
21 **“MISUNDERSTANDING” OF THE ECAPM. IS HE CORRECT?**

22 A. No, he is not correct. I fully understand the ECAPM. I also understand that few,
23 if any, regulatory commissions have seen fit to use the ECAPM as a primary

1 methodology with which to estimate the cost of equity. It is undisputable that the
2 ECAPM mathematically assigns the market beta (i.e., 1.0) as a twenty-five percent
3 *weight* (not to be confused with the above, separate discussion of beta's ability to capture
4 a useful representation of a percentage of company-specific *risk*) to the subject utilities in
5 the proxy group. This has the effect of over-stating the risk, beta, and required return for
6 all companies with a beta below 1.0. This is improper, as both myself and OTS witness
7 Plonski demonstrate.

8 **COMPARABLE EARNINGS METHOD (CE) ISSUES**

9 **Q. ON PAGE 46, MR. HANLEY INDICATES HIS BELIEF THAT YOUR**
10 **ASSOCIATION OF MARKET-TO-BOOK RATIOS AND RETURNS ON EQUITY**
11 **ARE "SUPPORTED BY NEITHER THE ACADEMIC LITERATURE NOR A**
12 **HISTORICAL ANALYSIS OF THE EXPERIENCE OF NON-PRICED**
13 **REGULATED COMPANIES." WHAT IS YOUR RESPONSE TO THIS?**

14 A. I disagree totally. Clearly, most public utilities have their rates regulated (i.e., set)
15 based upon the book value of their rate base and capital structure. In fact, the cost of
16 capital is reflected in the fair return on book value of common equity. Investors are
17 aware of this relationship (i.e., efficient market hypothesis, to again quote Mr. Hanley).
18 Any reference to the experience of unregulated companies, as is evident in Mr. Hanley's
19 Rebuttal Testimony, simply misses the point of public utility regulation.
20

1 **RISK ISSUES**

2 **Q. MR. HANLEY CLAIMS, ON PAGES 26-27 AND 53-54, THAT EQUITABLE GAS**
3 **SHOULD BE CONSTRUED AS A “SMALL” COMPANY, WITH RELATED**
4 **HIGHER RISK, BECAUSE IT IS A SEPARATE DIVISION/SUBSIDIARY.**
5 **WHAT IS YOUR RESPONSE TO THE CLAIM?**

6 A. I disagree with Mr. Hanley. Equitable Gas does not raise equity capital – this is
7 done by Equitable Resources. If a holding company chooses to create and/or operate a
8 series of relatively small subsidiaries (regulated or unregulated), this does not indicate
9 that each subsidiary should have a higher cost of equity. Equity investors evaluate
10 Equitable Resources, from a size perspective, as a large company, not a small company.
11 It is unjust, and inappropriate, to ask Equitable Gas’ ratepayers to pay higher rates based
12 on some fictitious claim that the enterprise that raised capital is small. Therefore, the 25
13 basis point upward adjustment that Mr. Hanley makes should be rejected.

14 **Q. MR. HANLEY FURTHER MAINTAINS, ON PAGES 24 AND 54, THAT**
15 **EQUITABLE GAS HAS HIGHER RISK BECAUSE IT DOES NOT HAVE**
16 **REVENUE DECOUPLING MECHANISMS AND/OR WEATHER**
17 **NORMALIZATION ADJUSTMENT CLAUSES. DO YOU AGREE?**

18 A. No, I do not. As I indicated in my direct testimony (page 47), there are multiple
19 reasons why this is not appropriate. There is nothing in Mr. Hanley’s rebuttal testimony
20 that alters those factors on the inappropriateness of Mr. Hanley’s proposed upward
21 adjustment of 20 basis points for what he calls “lack of protection in rate design.”
22

1 Q. FINALLY, ON PAGES 54-55, MR. HANLEY CONTINUES TO MAINTAIN
2 THAT "HEAD TO HEAD COMPETITION" ALLEGEDLY FACED BY
3 EQUITABLE GAS SHOULD BE ACCOMPANIED BY A 50 BASIS POINT
4 INCREASE IN THE COMPANY'S COST OF EQUITY. WHAT IS YOUR
5 RESPONSE TO THIS?

6 A. Mr. Hanley is ignoring the reality of this perceived competition. As I indicated in
7 my direct testimony (pages 47-48), it is the ratepayers who are bearing the risk. The
8 Company has asked its ratepayers to pay for any discounts given to customers who have
9 competitive options. Mr. Hanley does not acknowledge this in his rebuttal testimony. He
10 also does not acknowledge the double-recovery of these discounts that would occur if his
11 risk adjustment were adopted.

12 Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

13 A. Yes, it does.
14
15

16 106410

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08
NB6, PA

RJS

Pennsylvania Public Utility Commission,

v.

Equitable Gas Company

Independent Oil and Gas Association of
Pennsylvania

v.

Equitable Gas Company

Docket No. R-2008-2029325, et al

C-20066800

DIRECT TESTIMONY OF

GLENN A. WATKINS

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

NEGOTIATED REVENUE AND RATE STRUCTURE

OCTOBER 8, 2008

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1 **I. INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A. My name is Glenn A. Watkins. My business address is James Center III, 1051
4 East Cary Street, Suite 601, Richmond, VA 23219.

5 **Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?**

6 A. I am a Principal and Senior Economist with Technical Associates, Inc., which is
7 an economic and financial consulting firm with an office in Richmond, Virginia. Except
8 for a six month period during 1987 in which I was employed by Old Dominion Electric
9 Cooperative, as its forecasting and rate economist, I have been employed by Technical
10 Associates continuously since 1980.

11 During my career at Technical Associates, I have conducted marginal and
12 embedded cost of service, rate design, cost of capital, and load forecasting studies
13 involving numerous electric, gas, water/wastewater, and telephone utilities, and have
14 provided expert testimony in Alabama, Arizona, Georgia, Kentucky, Maine, Maryland,
15 Massachusetts, Michigan, New Jersey, Illinois, Pennsylvania, Vermont, Virginia, South
16 Carolina, Washington, and West Virginia. A more complete description of my education
17 and experience is provided in my Schedule GAW-1.

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

19 A. Technical Associates was engaged to evaluate the accuracy and reasonableness of
20 Equitable's class cost of service studies, proposed class revenue distribution (class
21 revenue allocation), proposed Residential rate design, and its proposed revenue discounts
22 for ratemaking purposes. The purpose of my testimony, therefore, is to present the

1 results of my studies and findings and offer recommendations regarding these issues to
2 the Commission.

3 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS**

4 A. I have conducted a class cost of service study utilizing the Peak and Average
5 Method and have determined that once the Residential class pays for all Universal
6 Service Fund ("USF") costs the following indexed class rates of return on rate base are
7 achieved:

Class	Rate of Return
Residential (RS)	107%
Small General Service (GSS)	216%
Large General Service (GSL)	91%
Appalachian Gathering Service (AGS)	-35%
Total	100%

14
15 I recommend that due to the different business operations of gathering service compared
16 to natural gas local distribution service, Appalachian Gathering Service ("AGS") should
17 be priced at full cost of service. I recommend that the Small General Service Class
18 ("GSS") should receive significantly less of an increase in revenue responsibility due to
19 its high relative (indexed) rate of return, and that the Large General Service ("GSL")
20 class should receive somewhat more than the LDC average increase (after Universal
21 Service requirements are collected), and the Residential class should receive the entire
22 Universal Service Fund shortfall along with a somewhat smaller percentage increase to
23 non-USF requirements than the LDC classes overall. My recommended class revenue
24 allocation proposal results in the following percentage increases to distribution revenue
25 using the Company's overall requested increase of \$51.95 million (33%); Residential,

34.4%; Small General Service, 9.1%; Large General Service, 19.9%; and Appalachian Gathering Service, 141.2%.

With regard to Residential rate design, I recommend increasing the current monthly customer charge from \$11.65 to \$12.50. I also recommend rejection of Equitable's proposed NRG retainage discount surcharge. Finally, I have found that Equitable has provided no support for its revenue deficiency resulting from discounted negotiated distribution rates. Equitable is requesting the Commission to require captive ratepayers to pay for these discounts without any verification or support. As such, I recommend a ratemaking disallowance of these discounts for purposes of determining captive ratepayers' distribution rates. This disallowance equals approximately \$22.7 million.

II. CLASS COST OF SERVICE

Q. PLEASE EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS").

A. There are two general types of cost of service studies used for public utility ratemaking: marginal cost studies and embedded, fully allocated cost studies. Equitable has utilized a traditional embedded cost of service concept in this case for purposes of establishing its overall retail revenue requirement, as well as for its CCOSS. Embedded cost of service studies are often referred to as fully allocated cost studies. This is because the vast majority of a public utility's plant investment serves all customers, and the majority of expenses are incurred in a joint manner such that these costs cannot be specifically attributed to any individual customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer (or group of customers), these costs are directly assigned in a CCOSS. However, the vast majority of

Equitable's plant and expenses are incurred jointly to serve all (or most) customers. These joint costs are then allocated to rate classes.

It is generally recognized that to the extent possible, joint costs should be allocated to classes based on the concept of cost causation; i.e., costs are allocated based on specific factors that cause costs to be incurred by the utility. Although cost analysts generally strive to abide by the concept of cost causation to the greatest extent practical, some costs (particularly overhead costs), cannot be attributed to specific exogenous factors and must be subjectively assigned or allocated to rate classes. With regard to those costs that can be attributed to a specific factor, cost of service experts often disagree as to what is the most cost causative factor; e.g., peak demand, energy usage, number of customers, etc.

Q. HOW SHOULD CCOSS RESULTS BE USED IN THE RATEMAKING PROCESS?

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive costs. These disagreements can and do arise as a result of the quality of data and the level of detail available from financial records. Moreover, there are often fundamental differences in opinions regarding cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Additionally, and as mentioned earlier, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In this regard, two different cost studies conducted for the same utility and for the same time period can, and often do, yield different results. As such, regulators should consider CCOSS results as one of many tools in assigning revenue responsibility.

1 **Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF**
2 **EQUITABLE'S CCOSS.**

3
4 A. The process by which I conducted my analysis in this case was identical to how I
5 evaluate all CCOSS. First, I reviewed the structure and organization of the Company's
6 CCOSS presented by Equitable witness, Russell A. Feingold. Once the basic structure
7 was understood, I reviewed the accuracy and completeness of the primary drivers
8 (allocators) used to assign costs to rate schedules and classes. Next, I reviewed Mr.
9 Feingold's selection of allocators used to allocate specific rate base, revenue and expense
10 accounts to customer rate classes. I then verified the accuracy of Mr. Feingold's CCOSS
11 model by reasonably replicating his results using my own computer model. Finally, I
12 adjusted certain aspects of the Company's studies to better reflect cost causation and cost
13 incidence by rate schedule and customer class.

14 **Q. DID YOU FIND THE COMPANY'S CCOSS TO BE MATHEMATICALLY**
15 **ACCURATE?**

16
17 A. Yes with regard to arithmetic. No with regard to accounting and financial
18 principles. Perhaps the two most fundamental requirements of an embedded CCOSS are
19 that the sum of the parts (customer classes) must equal the whole (system) and that the
20 arithmetic within the model must adhere to basic accounting and financial principles.
21 With respect to arithmetic, the allocation of financial accounts, as well as the various
22 allocation factors must add across classes as well as through the basic accounting model
23 (similar to an income statement and balance sheet). Mr. Feingold's model is accurate,
24 however, I did discover a material error in his determination of income tax responsibility.
25 I will explain this income tax error later in my testimony.
26

1 **Q. PLEASE PROVIDE A SUMMARY OF MR. FEINGOLD'S CCROSS RESULTS AT**
2 **CURRENT RATES.**

3
4 A. Mr. Feingold conducted two separate CCROSS using different distribution plant
5 allocation methodologies. Mr. Feingold conducted one study (at current and Equitable's
6 proposed rates) using the Peak Responsibility Method in which distribution Mains were
7 classified as partially customer-related and partially demand-related. Mr. Feingold also
8 conducted a study utilizing the Peak and Average Method to allocate Mains with no
9 customer classification of Mains investment. Mr. Feingold's two CCROSS generate the
10 following absolute and indexed rates of return on rate base at current rates, using
11 Equitable's proposed forecasted test year amounts:

Class	Peak and Average		Peak Responsibility	
	Rate of Return	Indexed Rate of Return	Rate of Return	Indexed Rate of Return
Residential (RS)	2.90%	76%	1.54%	41%
Small General Service (GSS)	17.02%	447%	18.15%	477%
Large General Service (GSL)	5.83%	153%	12.26%	322%
Appalachian Gathering Service (AGS)	-6.69%	-176%	-6.69%	-176%
Total	3.80%	100%	3.80%	100%

12
13
14
15
16
17
18
19
20 **Q. MR. WATKINS, BEFORE YOU DISCUSS THE SPECIFICS OF YOUR**
21 **DISAGREEMENTS WITH MR. FEINGOLD'S APPROACH, PLEASE EXPLAIN**
22 **THE BASIC CONCEPTS OF COST ALLOCATION FOR PUBLIC UTILITIES**
23 **AND NATURAL GAS LDCs.**

24
25 A. As I mentioned earlier (and also discussed by Mr. Feingold in his testimony), the
26 majority of a LDC's plant investment serves customers in a joint manner. In this regard,
27 the LDC's infrastructure is a system benefiting all customers. If all customers were the
28 same size and had identical usage characteristics, cost allocation would be simple (even
29 unnecessary), in that costs and prices could be efficiently and fairly assigned and
30 developed simply by dividing total costs by number of customers to arrive at an average

1 cost (price) per customer. However, in reality, a utility's customer base is not so simple.
2 Customers (or customer groups) tend to vary greatly in the amount of service required
3 throughout the year such that there are small usage and large usage customers.
4 Therefore, differences in customer usage should be considered. Because different groups
5 of customers also utilize the system at varying degrees during the year, consideration
6 should also be given to the demands placed on the system during peak usage periods.

7 **Q. WHY DO COST ANALYSTS SOMETIMES CLASSIFY AND ALLOCATE A**
8 **PORTION OF DISTRIBUTION PLANT ON THE NUMBER OF CUSTOMERS?**
9

10 A. Largely as a result of differences in customer densities throughout a utility's
11 service area, utility distribution plant is sometimes classified as partially demand-related
12 and partially customer-related. Possibly the best way to explain why customer densities
13 may be important in the assignment of distribution costs to individual classes is by way
14 of example. Consider two different utilities: a rural electric utility with urban, suburban,
15 and rural service areas and another utility with only urban and suburban customers. With
16 respect to the utility with a rural service area, many miles of conductors and associated
17 plant must be installed in order to serve the demands of relatively few customers.
18 Conversely, many more customers are served on a per mile basis for the urban/suburban
19 utility. With respect to the utility with a rural service area, such an allocation based on
20 usage or demand may be unfair if some classes are located mainly in urban or suburban
21 areas, while other classes of customers are located in urban, suburban, and rural areas.
22 As a result, some cost studies classify Distribution plant as partially demand-related and
23 partially customer-related.
24

1 **Q. IN THE ABOVE EXAMPLE YOU REFERRED TO ELECTRIC UTILITIES**
2 **INSTEAD OF NATURAL GAS UTILITIES. IS THERE A REASON WHY YOU**
3 **SELECTED THE ELECTRIC UTILITY INDUSTRY FOR YOUR EXAMPLE?**

4
5 A. Yes. Although the concepts are the same between electric and natural gas
6 distribution facilities (e.g., conductors are synonymous with Mains), electric utilities are
7 required to serve rural, (sparsely populated) areas. Such requirements are not in place for
8 natural gas LDCs.

9 As such, and as a general matter, a customer/demand classification of electric
10 distribution facilities may be appropriate in some circumstances given the characteristics
11 of a service area, but is rarely appropriate for natural gas LDCs, whose service areas are
12 more densely populated.

13 **Q. HOW APPROPRIATE IS A CUSTOMER/DEMAND SEPARATION FROM A**
14 **DESIGN OR OPERATIONAL PERSPECTIVE?**

15
16 A. First and foremost, the classification of distribution plant as partially customer,
17 and partially demand-related results from the view that the assignment of these plant
18 items to classes based solely on a demand allocator would not be equitable to some
19 classes. I emphasize this point, because many analysts "lose sight of the forest for the
20 trees." When classifying individual accounts within distribution plant, analysts
21 sometimes do not consider how a distribution system is designed and connected.

22 There are four major factors the analyst should keep in mind when classifying
23 natural gas distribution plant. First, is the fact that purchasing economies are usually
24 present. For example, there are many types and sizes of pipe manufactured. However,
25 due to purchasing economies, a utility may purchase only a few different sizes of pipe.
26 This will result in some "over capacity," however, the total installed cost will be less than
27 if every segment of the system is optimally sized. Second, most components of the

1 distribution system are somewhat oversized for other reasons, such as pressure
2 equalization, safety, reliability, and growth uncertainty. Third, historical asset records
3 reflecting capitalized labor and material costs by size and type of investment are far from
4 perfect, especially in older systems such as Equitable. Reasons for less than perfect
5 record keeping include: the loss of data over time, the changing needs of record keeping
6 by a Company, data processing limitation, different record keeping practices and detail
7 by companies prior to mergers/acquisition by other companies. These asset records are
8 the underlying source for conducting minimum size and zero-intercept studies. Fourth,
9 and particularly relevant to Equitable, is that the utilization and operation of a particular
10 distribution system currently may be significantly different than when the system was
11 constructed; i.e., a large decrease in customers, loads, and throughput.

12 Although these factors are reflective of how distribution systems are actually
13 installed and operated, classification studies do not account for these factors. In fact, the
14 presence of these factors can seriously skew the results of such studies.

15 **Q. EARLIER YOU INDICATED THAT MR. FEINGOLD CONDUCTED BOTH**
16 **PEAK AND AVERAGE AND PEAK RESPONSIBILITY CCROSS. DO YOU**
17 **HAVE ANY COMMENTS REGARDING MR. FEINGOLD'S USE OF THESE**
18 **ALLOCATION METHODOLOGIES?**

19
20 **A.** Yes. As acknowledged by Mr. Feingold, this Commission has expressed a clear
21 preference for allocation methodologies that consider both throughput (average use) and
22 peak day demand. The Peak and Average method accomplishes this goal and is the most
23 widely used in the natural gas industry in which throughput is considered.

1 **Q. DO YOU AGREE WITH THE COMMISSION'S PREFERENCE TO RELY ON**
2 **CCOSS METHODOLOGIES, SUCH AS THE PEAK AND AVERAGE, THAT**
3 **CONSIDER BOTH THROUGHPUT AS WELL AS PEAK DEMAND FOR**
4 **PURPOSES OF ASSIGNING EQUITABLE'S COST RESPONSIBILITY?**

5
6 A. Yes. There are several reasons why the Peak and Average Method is preferred
7 and why the peak responsibility method is not appropriate for Equitable. The first is the
8 recognition of how and why natural gas consumers are customers of Equitable. That is,
9 customers connect to Equitable's system in order to meet their natural gas needs
10 throughout the year. Indeed, the Company's Mains are utilized each and every day of the
11 year and recognition of annual usage (throughput) is a logical basis for cost assignment.

12 Another shortcoming of the peak responsibility method using design day demands
13 is that the "design day" is a moving target over time. That is, whereas natural gas Mains
14 are planned and installed to serve customers in excess of fifty years into the future, design
15 day demand (as used by Mr. Feingold) is a function of the mix, usage per customer, and
16 number of customers today. In other words, Mr. Feingold's design day demand allocator
17 is based on today's mix and configuration even though the majority of Mains were
18 installed when the Equitable system was configured much differently. Indeed, this is
19 particularly true for Equitable given its age and the much larger industrial load that was
20 once on the system. Many Mains in service today were installed to serve the
21 consumption and loads of industrial customers that no longer exist. In addition,
22 Equitable's commercial centers have obviously changed over the last few decades. Yet,
23 Mr. Feingold assumes the entire Company system was optimally designed and installed
24 to meet today's mix and level of customers.

1 **Q. HOW HAVE YOU ALLOCATED DISTRIBUTION MAINS IN YOUR CCROSS?**

2 A. For reasons discussed earlier, I have adhered to this Commission's preferred
3 approach, and I did not classify Mains as partially customer-related such that no portion
4 of Mains is allocated based on customer counts in my study. I have allocated Mains costs
5 using the Peak and Average method in which equal weight is given to annual throughput
6 (average demand) and design day peak demand. In my opinion, the Peak and Average
7 method is particularly well suited for Equitable given the age of the system and changes
8 in customers that have taken place over the years in which plant was installed and
9 currently remains in service.

10 **Q. YOU STATED EARLIER THAT YOU REASONABLY REPLICATED MR.**
11 **FEINGOLD'S RESULTS. WERE YOU ABLE TO EXACTLY REPLICATE MR.**
12 **FEINGOLD'S STUDY RESULTS?**

13
14 A. No. Mr. Feingold's computer model is extremely, and in my opinion needlessly,
15 complicated. In order to explain Mr. Feingold's modeling process consider that the end
16 result is the allocation of each rate base and operating income account to the various rate
17 classes. As such, the ultimate results of any CCROSS show class allocations of rate base
18 and operating income to assess profitability. With the ultimate objective and outcome in
19 mind, Mr. Feingold functionalized every rate base and operating income account into five
20 categories: "Production & Gathering;" "Storage;" "Transmission;" "Distribution;" and,
21 "Onsite;" i.e., Mr. Feingold first allocated each account into five groups. Next, Mr.
22 Feingold further divided his distribution functionalized accounts for each and every
23 account in order to "classify" these allocated costs into customer and demand
24 components. In other words, another complete set of allocations were performed. At this
25 point, Mr. Feingold's model has six fully allocated groups of costs for each rate base and

1 operating income account. The third step is actually six independent iterations (one for
2 each fully allocated group of costs) of allocations to the various classes for each account.
3 Although, Mr. Feingold's model should theoretically work since a fundamental principle
4 of all CCOSS is that the sum of all parts and subparts must ultimately equal the whole
5 (Total Company), it is virtually impossible to verify all of Mr. Feingold's calculations
6 without access to his computerized model. A schematic of Mr. Feingold's model is
7 provided in my Schedule GAW-2.

8 In a current case involving Columbia Gas of Ohio (Ohio PUC) in which both Mr.
9 Feingold and I are participating, my staff and I spent numerous hours simply verifying
10 Mr. Feingold's model. In that case, I did discover a few errors in Mr. Feingold's model
11 that when corrected, were immaterial to the end results (class rates of return). Due to
12 Equitable's refusal to provide access to Mr. Feingold's computerized model, I took a
13 somewhat different approach in this case.

14 Mr. Feingold's study is well documented such that I was able to understand the
15 basis for his allocations. Other than an income tax error that I will discuss later in my
16 testimony, I found Mr. Feingold's conceptual bases for allocating individual accounts to
17 classes within the range of reasonableness, so I accepted his bases for allocation as close
18 as possible and applied these to my more traditional CCOSS model; i.e., I accepted his
19 choice of allocators for individual costs. Because there is not a perfect consistency
20 between Mr. Feingold's functionalization stage and his allocation stage, minor
21 differences occur in allocated class amounts for some accounts. As such, I did not
22 exactly replicate his CCOSS results.

For purposes of comparison, the following is a summary of Mr. Feingold's and my CCOSS results using the Peak and Average method and before any corrections are made to his COSS:

Class	Return on Rate Base at Current Rates			
	ROR		Indexed ROR	
	Feingold	Watkins	Feingold	Watkins
Residential (RS)	2.90%	2.87%	76%	75%
Small General Service (GSS)	17.02%	17.24%	447%	453%
Large General Service (GSL)	5.83%	5.74%	153%	151%
Appalachian Gathering Service (AGS)	-6.69%	-5.94%	-176%	-156%
Total	3.80%	3.81%	100%	100%

Q. PLEASE EXPLAIN MR. FEINGOLD'S ERROR RELATING TO INCOME TAXES.

A. While conducting my examination of Mr. Feingold's Peak Responsibility CCOSS presented in 53.53 IV-B-1(A), I observed nonsensical results. Whereas Mr. Feingold calculates the GSL class rate of return on rate base (ROR) to be 12.26% at current rates, he also calculates that a rate increase of \$173,000 is required to reduce this class' ROR to 8.89%.

I ultimately discovered Mr. Feingold's error. This error is in his determination of class income taxes. It is well known that taxable income is equal to the following amounts:

	Revenues,
less	Operating & Maintenance Expense,
less	Depreciation Expense,
less	Taxes Other Than Income Taxes;
less	<u>Interest Expense,</u>
equals	Taxable Income.

While some CCOSS analysts ignore interest expense for simplicity, everyone would agree that Operating and Maintenance expenses should be deducted from net revenues in determining taxable income and income tax responsibility. Although I am certain it was unintentional, Mr. Feingold failed to deduct Operating and Maintenance expenses in determining class income tax responsibility. Instead, Mr. Feingold's class income taxes are based on revenues minus depreciation minus taxes other than income taxes. As a result of this error, Mr. Feingold's CCOSS model (both Peak Responsibility and Peak and Average) produces incorrect class ROR's. In addition, Mr. Feingold did not reflect interest expense in his determination of income tax responsibility.

Q. HAVE YOU CORRECTED THE INCOME TAX ERRORS PRESENT IN MR. FEINGOLD'S CCOSS?

A. Yes. Because I sponsor only the Commission's preferred Peak and Average methodology, the following is a comparison of the Peak and Average class ROR's at current rates before and after the correction for Mr. Feingold's income tax errors.

Class	Peak and Average ROR at Current Rates	
	Before Income Tax Correction	After Income Tax Correction
Residential (RS)	2.87%	3.33%
Small General Service (GSS)	17.24%	11.40%
Large General Service (GSL)	5.74%	4.78%
Appalachian Gathering Service (AGS)	-5.94%	-1.75%
Total	3.81%	3.81%

As can be seen above, this correction has a material impact on the ROR for the GSS and AGS classes.

Q. DID MR. FEINGOLD'S CCOSS CONTAIN ADDITIONAL ERRORS?

A. Yes.

1 **Q. PLEASE EXPLAIN THESE ADDITIONAL ERRORS IN MR. FEINGOLD'S**
2 **CCOSS.**

3
4 A. Although I respectfully disagree, this Commission has ruled on several occasions
5 that the Residential class should be solely responsible for low-income customer
6 assistance program costs (Universal Service costs). Mr. Feingold is apparently aware of
7 this Commission policy but failed to assign all Universal Service costs to the Residential
8 class in his CCOSS. In response to OSBA Data Request 1-4, Mr. Feingold
9 acknowledged errors in the assignment of Universal Service costs. Specifically, Mr.
10 Feingold assigned approximately \$350,000 of Universal Service shortfall costs included
11 in Account 904 (Uncollectibles) to the GSS class and approximately \$640,000 of such
12 costs to the GSL class. Similarly, Mr. Feingold inadvertently assigned approximately
13 \$299,000 in Universal Service related expenses included in Account 908 to all rate
14 classes.

15 **Q. DID YOU CORRECT FOR THESE OVERSIGHTS?**

16 A. Yes.

17 **Q. DO YOU HAVE ANY OTHER DISAGREEMENTS WITH MR. FEINGOLD'S**
18 **CCOSS?**

19
20 A. Yes. Whereas I recognize that Universal costs are to be the sole responsibility of
21 the Residential class due to previous Commission directives and findings, this Universal
22 Service Cost responsibility should not serve to increase the assignment of unrelated costs.
23 However, as a result of Mr. Feingold's use of composite, or internally generated
24 allocators to assign overhead and general corporate costs, the Residential class is further
25 burdened with Universal Service Cost responsibility. In other words, Mr. Feingold's
26 composite allocators are developed based on the assignment of other account costs,

including Universal Service costs assigned to the Residential class. It is not appropriate to further burden the Residential class with cost responsibility simply because it must bear all costs associated with the Universal Service Program. As indicated earlier, these composite allocators are used to allocate overhead and administrative costs. Furthermore, the Universal Service Program is already assigned \$299,000 in Corporate Administrative expenses, which are directly assigned totally to the Residential class as indicated in the Company's response to OSBA Data Request 1-4.

As a result, I have eliminated the effects of Universal Service direct assignments to the Residential class in developing composite, or internal, allocators. This elimination of double cost responsibility relates to internal allocators based on O&M Expenses.

Q. WHAT ARE YOUR CCOSS RESULTS AFTER CORRECTING FOR THE ASSIGNMENT OF DIRECT UNIVERSAL SERVICE COSTS TO THE RESIDENTIAL CLASS, AND ADJUSTING TO REFLECT THE ELIMINATION OF UNIVERSAL COSTS IN DETERMINING INTERNAL ALLOCATORS?

A. The following are my class ROR results using the Peak and Average Method and my recommended CCOSS. The details of my CCOSS are presented in my Schedule GAW-3:

Class	OCA CCOSS Results at Current Rates	
	Rate of Return	Indexed Rate of Return
Residential (RS)	3.24%	85%
Small General Service (GSS)	11.81%	310%
Large General Service (GSL)	4.95%	130%
Appalachian Gathering Service (AGS)	-1.89%	-50%
Total	3.81%	100%

1 **Q. DO THE ABOVE CLASS RATES OF RETURN AT CURRENT RATES**
2 **PROVIDE ADEQUATE GUIDANCE AS TO HOW CLASS REVENUE**
3 **RESPONSIBILITY SHOULD BE ASSIGNED?**
4

5 A. No. To the extent the Commission continues to adhere to its prior practice of
6 requiring the Residential class to be solely responsible for Universal Service costs, an
7 additional step is required to evaluate class revenue responsibility as one of many tools
8 that should be considered.

9 As was discussed earlier in my testimony, all Universal Service costs were
10 directly assigned to the Residential class. To the extent the Residential class is required
11 to bear all costs associated with the Universal Service Program, it is reasonable and
12 appropriate to also include the revenues generated to support these Universal Service
13 costs. Equitable claims that an additional \$16.865 million is required to fund its
14 Universal Service Program and indeed this exact amount is included as costs in the
15 CCOSS (\$16.167 in Account 904 plus \$0.698 in Account 910 per the Company's
16 response to OSBA Data Request 1-4).

17 As such, I have assigned the Universal Service revenue shortfall to be collected
18 through the Rider D surcharge (\$16.865 million) to the Residential class and evaluated
19 each class' absolute and relative profitability's at this level. As shown on page 1 of my
20 Schedule GAW-3, an additional \$16.865 million in revenue will result in a \$9.625
21 million in net operating income (profit). This additional revenue increases the total
22 Company ROR from 3.81% to 5.46%. Because all of this \$16.865 million increase is
23 borne by the Residential class, its ROR increases from 3.24% to 5.82%. A summary of
24 each class' ROR after the assignment of Universal Service cost revenues is presented
25 below:

Class	ROR After Universal Service Increase	
	Rate of Return	Indexed Rate of Return
Residential (RS)	5.82%	107%
Small General Service (GSS)	11.81%	216%
Large General Service (GSL)	4.95%	91%
Appalachian Gathering Service (AGS)	-1.89%	-35%
Total	5.46%	100%

As can be seen above, the GSS class is significantly above the system average ROR, the Residential class is somewhat above the system ROR, the GSL class is somewhat below, while the AGS class is substantially below the system average ROR.

III. CLASS REVENUE DISTRIBUTION

Q. PLEASE DESCRIBE EQUITABLE'S PROPOSED DISTRIBUTION OF ITS REQUESTED OVERALL REVENUE INCREASE TO INDIVIDUAL CUSTOMER CLASSES.

A. Equitable witness Quinn presents Equitable's proposed distribution of its requested \$51.950 million revenue increase to customer classes beginning at Page 9 of his Direct Testimony. Mr. Quinn's first step in his proposed revenue distribution approach was to separate the Company's requested Universal Service Fund costs of \$16.865 million, and directly assign these costs to the Residential class. The remaining revenue increase amount of \$35.085 million (\$51.950 million - \$16.865 million) was then distributed among the RS, GSS, GSL and AGS customer classes. Mr. Quinn states that he relied upon witness Feingold's CCOSS which provided "a perspective as to the rate of return earned by the Company for each customer class at current rates and to establish a range of reasonableness in evaluating the impact on the rates of return when allocating the increase in the Company's non-gas revenue requirement to each customer class" (Pages 10 and 11 of Mr. Quinn's Prepared Direct Testimony).

A summary of Equitable's proposed revenue increase for each customer class is shown below:

Equitable Proposed Gas Revenue Increases (\$000)					
Class	(1) Current Operating Revenue <u>a/</u>	(2) Proposed Revenue Increase <u>b/</u> Margin	(3) USF	(4) Total (2)+(3)	(5) Percent Increase (4)÷(1)
Residential (RS)	\$108,258	\$23,185	\$16,865	\$40,050	37.0%
Small General Service (GSS)	14,584	1,432	--	1,432	9.8%
Large General Service (GSL)	29,463	2,950	--	2,950	10.0%
Appalachian Gathering Service (AGS)	5,326	\$7,518	--	7,518	141.1%
Total	\$157,631	\$35,085	\$16,865	\$51,950	33.0%

a/ Equitable Exhibit IV, Item: 53.53 IV-B-1(B), Sheet 1 of 85.

b/ Equitable witness Quinn's Direct Testimony, Page 16.

Q. MR. WATKINS, IN YOUR OPINION ARE EQUITABLE'S PROPOSED CUSTOMER CLASS REVENUE INCREASES REASONABLE?

A. With regard to the AGS class (Appalachian Gathering Service), Mr. Quinn's proposal is reasonable for reasons I will explain later. With regard to the assignment of increases across the RS, GSS, and GSL classes, Mr. Quinn's proposal places unreasonable burdens on the Residential class and assigns too little revenue responsibility to the GSL class.

Q. DO YOU HAVE AN ALTERNATIVE REVENUE INCREASE DISTRIBUTION TO THAT PROPOSED BY MR. QUINN?

A. Yes, I do. Using the results of my CCOSS as a guide, and also considering the principles of gradualism, fairness and equity, I propose the following revenue increase distribution at Equitable's requested overall revenue level:

OCA Proposed Gas Revenue Increases
(\$000)

	(1)	(2)	(3)	(4)	(5)
					Percent of Current Operating Revenues (4)÷(1)
Class	Current Operating Revenue	Proposed Revenue Increase Margin	USF	Total (2)+(3)	
Residential (RS)	\$108,258	\$20,378	\$16,865	\$37,243	34.4%
Small General Service (GSS)	14,584	1,320	--	1,320	9.1%
Large General Service (GSL)	29,463	5,865	--	5,865	19.9%
Appalachian Gathering Service (AGS)	5,326	\$7,522	--	7,522	141.2%
Total	\$157,631	\$35,085	\$16,865	\$51,950	33.0%

In formulating my proposed gas revenue increase distribution to the various customer classes, I recognized the \$16.865 million increase required from the Residential class for Universal Service Fund costs, and used the results of my CCOSS as a guide in establishing class revenue responsibility in conjunction with the concepts of gradualism and fairness. My specific revenue allocation methodology is described narratively below with the actual calculations provided in schedule GAW-4:

(1) First, the AGS customer class was set to full cost of service (\$7.522 million). This is the same conceptual proposal made by Mr. Quinn;

(2) In order to recognize the higher than system average ROR provided by the GSS class, I next increased the GSS class margin revenues at 50% of the remaining system average percentage increase of 18.1%, which represents the remaining revenue increase of \$27.563 million (\$51.950 million - \$16.865 million - \$7.522 million) developed by current operating revenues of \$152.305 million for RS, GSS and GSL. This

1 procedure results in an increase of 9.1% (\$1.320 million) to the GSS
2 class.

3
4 (3) Because the GSL is somewhat below system average ROR, once
5 Universal Service costs are recovered I increased GSL at 110% of the
6 percentage increase of 18.1% described in (2). This results in an increase
7 to the GSL class of \$5.865 million or 19.9%; and,

8
9 (4) Finally, I treated the RS class as the residual to recover the remainder of
10 the required revenue increase of \$20.378 million. This \$20.378 million
11 increase coupled with the \$16.865 million increase associated with the
12 Universal Service Fund, results in a total increase to the Residential class
13 of \$37.243 million or 34.4%.

14 **Q. WHY IS IT APPROPRIATE TO MOVE APPALACHIAN GATHERING**
15 **SERVICE ALL THE WAY TO FULL COST OF SERVICE?**

16
17 A. Equitable's gathering service is a totally different line of business from its natural
18 gas distribution operations. As such, the gathering service, should be regulated as a self
19 supporting line of business. In other words, consider a Company that has both interstate
20 transmission pipeline operations as well as local distribution operations. This Company's
21 pipeline operations are priced at its full cost of service, while the LDC operations are
22 considered separately and also priced at full cost of service.

1 **Q. DOES YOUR PROPOSED REVENUE DISTRIBUTION MOVE CUSTOMER**
2 **CLASSES TOWARDS RATE OF RETURN PARITY?**

3
4 A. Yes. As shown below, and provided in detail on Page 1 of Schedule GAW-3, my
5 proposed class revenue assignment moves AGS to full cost of service, while the GSS, RS
6 and GSL classes all move closer to rate of return parity.

OCA Indexed ROR		
At Proposed Revenue Increase Of \$51.950 Million		
Class	At Current Rates W/O Univ. Svc. Revenue	At Proposed Increase
Residential (RS)	85%	101%
Small General Service (GSS)	310%	157%
Large General Service (GSL)	130%	84%
Appalachian Gathering Service (AGS)	-50%	100%
Total	100%	100%

15
16 **Q. MR. WATKINS, THE GSS CLASS' ROR IS STILL CONSIDERABLY ABOVE**
17 **THE SYSTEM AVERAGE UNDER YOUR CLASS REVENUE ALLOCATION**
18 **PROPOSAL. WOULD IT BE REASONABLE TO ASSIGN NO INCREASE TO**
19 **THIS CLASS?**

20
21 A. No. While CCOSS results should play an important role in establishing class
22 revenue responsibility, it should not be the only consideration. The concept and
23 principles of gradualism and fairness should also be considered. Equitable is requesting
24 an increase in total distribution revenues of 33%. My revenue allocation proposal
25 provides significant movement such that the GSS class' relative ROR goes from 310% of
26 the system average ROR to 157% of the system average ROR. This gradualism should
27 then be applied to the subjective evaluation of fairness. In my opinion, it would not be
28 fair to increase total Company revenues by 33%, require Residential customers to bear a
29 34% increase in base rates, and at the same time provide a zero increase to Small
30 Commercial and Industrial customers (GSS class).

1 **Q. MR. WATKINS, PLEASE PROVIDE YOUR RECOMMENDED SCALE BACK**
2 **METHOD TO ASSIGN CLASS REVENUE INCREASES SHOULD THE**
3 **COMMISSION AUTHORIZE AN OVERALL REVENUE REQUIREMENT**
4 **INCREASE LESS THAN THAT PROPOSED BY EQUITABLE.**

5
6 A. I recommend first, any adjustment to Universal Service costs be reflected in the
7 Residential Universal Service portion of the allowed increase, and second, my customer
8 class revenue increase for RS, GSS and GSL be reduced proportionally downward, while
9 maintaining the revenue increase to AGS at full cost of service.

10 **IV. RESIDENTIAL RATE DESIGN**

11 **Q. PLEASE DESCRIBE EQUITABLE'S CURRENT RESIDENTIAL RATE**
12 **STRUCTURE?**

13
14 A. Currently, Residential rates include a fixed monthly customer charge of \$11.65, a
15 flat usage charge for all gas consumed (\$2.703/MCF), a Universal Service rider (Rider D)
16 of \$0.580/MCF, and a Transition Cost Recover Surcharge (Rider C) of \$0.227/MCF.

17 **Q. WHAT RATE STRUCTURE DOES EQUITABLE PROPOSE FOR**
18 **RESIDENTIAL CUSTOMERS IN THIS CASE?**

19
20 A. Equitable proposes to maintain its flat usage charge, replace its Universal Service
21 Rider, eliminate its Transition Cost Recovery Surcharge and implement a new NRG
22 Energy Price Discount Surcharge Rider.

23 **Q. DO YOU HAVE ANY OBJECTIONS TO THE STRUCTURES OF EQUITABLE'S**
24 **RESIDENTIAL RATES?**

25
26 A. I have no objections to the basic structure of Equitable's Residential rates, its
27 Rider D, or the elimination of the Transition Cost Recovery Surcharge. I do, however,
28 oppose the Company's proposed surcharge relating to NRG discounts. Mr. Colton will
29 discuss the details of Rider D in his testimony.

1 **Q. WITH RESPECT TO THE CURRENT RESIDENTIAL CUSTOMER CHARGE**
2 **OF \$11.65, DOES EQUITABLE PROPOSE AN INCREASE TO THIS FIXED**
3 **MONTHLY RATE?**

4
5 A. Yes. Equitable witness Quinn recommends an increase to the monthly
6 Residential customer charge from the current \$11.65 level to \$20.00.

7 **Q. DOES MR. QUINN PROVIDE ANY JUSTIFICATION FOR THIS LARGE**
8 **INCREASE IN THE FIXED CUSTOMER CHARGE?**

9
10 A. Mr. Quinn indicates that the Company believes it is reasonable and appropriate to
11 continue to move the monthly service charges closer to the calculated average monthly
12 customer cost. As part of his CCOSS, Mr. Feingold conducted two separate "customer
13 cost" analyses presented in Filing Exhibit IV-B-9. These two customer cost analyses
14 correspond to the Company's Peak Responsibility and Peak and Average CCOSS. Mr.
15 Feingold's customer cost analyses result in a Residential "customer cost," of \$32.25 to
16 \$36.23.

17 **Q. DO YOU AGREE WITH MR. FEINGOLD'S "CUSTOMER COST" ANALYSIS?**

18 A. No. Mr. Feingold's customer cost analyses include not only those costs that are
19 directly attributable to customers but also assigns a significant level of corporate
20 overhead costs. In my opinion, any customer cost analysis used as a basis for
21 establishing fixed monthly customer charges should only include direct customer costs.

22 **Q. HAVE YOU CONDUCTED SUCH A DIRECT CUSTOMER COST ANALYSIS?**

23 A. Yes. The results of my direct customer cost analysis are presented in my
24 Schedule GAW-5 and result in a monthly Residential customer cost of \$13.14.

1 Q. **WHAT IS YOUR RECOMMENDATION AS TO RESIDENTIAL CUSTOMER**
2 **CHARGES IN THIS CASE?**

3
4 A. Given the very high current customer charge of \$11.65 and my direct customer
5 cost analysis that results in a monthly customer cost of \$13.14. I recommend a monthly
6 customer charge of \$12.50 regardless of any increase in revenue requirement authorized
7 by this Commission.

8 Q. **FOR PURPOSES OF COMPARISON, HAVE YOU EVALUATED COMMISSION**
9 **APPROVED RESIDENTIAL CUSTOMER CHARGES FOR OTHER NATURAL**
10 **GAS LDC'S IN PENNSYLVANIA?**

11
12 A. Yes. My Schedule GAW-6 provides a list of current Residential customer
13 charges for natural gas LDC's in Pennsylvania. As can be seen, these monthly customer
14 charges range from a high of \$12.50 (T.W. Phillips) to a low of \$2.75 (Sergeant). As
15 such, my recommended customer charge of \$12.50 will place Equitable at the top of the
16 highest Residential customer charges in the State.

17 V. **NEGOTIATED RATE REVENUE**

18 Q. **PLEASE EXPLAIN WHAT IS MEANT BY THE TERM "NEGOTIATED**
19 **RATES" AS IT RELATES TO EQUITABLE GAS' REGULATED BUSINESS.**

20
21 A. Although this Commission establishes specific fair and reasonable rates for each
22 of Equitable's local distribution company ("LDC") rate schedules, the Company has
23 proposed to continue its practice of deviating downward from these approved rates for
24 selected customers; i.e., Equitable offers discounted distribution rates to certain
25 customers.

1 **Q. DO OTHER NATURAL GAS LDC'S IN PENNSYLVANIA ENGAGE IN THE**
2 **PRACTICE OF NEGOTIATING RATES DOWNWARD FROM THE**
3 **APPROVED, FULL TARIFF, RATES?**
4

5 A. *It is my understanding that the practice of negotiated rates has been prevalent in*
6 western Pennsylvania as a result of what is known as "gas on gas" competition. This gas
7 on gas competition exists primarily because of the way natural gas distribution systems
8 evolved in the Pittsburgh area prior to regulation. This gas on gas competition results
9 from the geographic location of specific customers such that certain natural gas
10 customers are located in close proximity to either interstate pipelines or other natural gas
11 LDC's. It should be noted that customers who are not located in reasonably close
12 proximity to alternative natural gas facilities, are not eligible for gas on gas negotiated
13 rate discounts as a practical manner. Furthermore, these geographic proximity reasons
14 for discounted rates apply to all classes of customers in varying degrees throughout
15 western Pennsylvania.

16 With regard to rate discounts associated with gas on gas competition among
17 LDC's, I do not think it in the public interest to continue such a practice. This is true
18 because the benefits that generally accrue due to competitive market forces are only
19 available to selected customers purely based on geographic location within a utility's
20 service area. Furthermore, gas on gas competition among natural gas LDC's is a zero
21 sum game with captive ratepayers being the losers.

22 While it is true that revenue generated from discounted rate customers contributes
23 to the recovery of gas utilities fixed costs and thereby result in lower rates than if no
24 revenue was achieved from discounted rate customers, the downward spiral in negotiated
25 rates due to LDC versus LDC competition is a zero sum game as far as societal resources

1 are concerned. As an example, captive customer rates served by Utility A are higher than
2 they otherwise would be due to Utility B attempting to gain business from certain Utility
3 A customers. Similarly, captive customers served by Utility B are higher than they
4 otherwise would be due to Utility A attempting to gain the business of selected customers
5 from Utility B.

6 **Q. WHAT RELEVANCE DO THESE DISCOUNTED RATES HAVE TO THE**
7 **RATEMAKING PROCESS?**
8

9 A. Equitable seeks authorization to insulate its shareholders from the effects of
10 competition resulting from a reduction in earnings due to its discounting of revenues, and
11 requests captive ratepayers over which the Company has monopoly power, to bear and
12 pay for the shortfall in revenues from authorized rates. In other words, Equitable is
13 asking the Commission to set captive customers' rates based on the cost to serve them,
14 and also seeks an add-on to these cost based rates due to discounts given certain other
15 customers.

16 **Q. DID EQUITABLE PROVIDE ANY INFORMATION IN ITS APPLICATION,**
17 **WITNESSES' TESTIMONY, OR WORKPAPERS CONCERNING ITS REQUEST**
18 **TO EXEMPT SHAREHOLDERS FROM RESPONSIBILITY FOR DISCOUNTED**
19 **RATE REVENUES?**
20

21 A. No. Company witness John Quinn provides three qualitative reasons as to why
22 the Company offers discounted rates on a selective basis. But, no support for, or
23 verification of these discounts were provided in the Company's application, workpapers,
24 or testimony.

25 **Q. DID EQUITABLE MAKE A SPECIFIC RATEMAKING ADJUSTMENT TO**
26 **REFLECT DISCOUNTED REVENUES FROM CERTAIN CUSTOMERS?**
27

28 A. No. Instead of specifically requesting its proposed regulatory treatment of
29 discounted rate revenues, Equitable presented its revenues in a summary fashion. To

1 illustrate, Filing Exhibit III, Item III-E-20 presents a standard revenue proof at current
2 rates for all revenue generated from captive (non-discounted) customers. This revenue
3 proof follows standard industry practice of presenting each rate schedule's billing
4 determinants and Commission approved rates to develop (or "prove") revenues. Such is
5 not the case for revenue resulting from discounted rates, in that no "proof" or justification
6 of the revenues is presented. Instead, the total level of discounted rate revenues are
7 simply added to the detailed proof of revenue analysis conducted for captive, full tariff,
8 customers.

9 **Q. BASED ON YOUR UNDERSTANDING OF THE RULES RELATING TO RATE**
10 **CASES, IS EQUITABLE REQUIRED TO PROVIDE A PROOF OF REVENUES**
11 **ASSOCIATED WITH DISCOUNTED RATES?**

12
13 A. Yes. Title 52 Pa. Code §53.53 III E.11 states the following:

14 "Provide a detailed billing analysis supporting present and proposed rates
15 by customer classification and/or tariff rate schedule."
16

17 The requirement is clear that a detailed billing analysis is to be provided. The simple
18 inclusion of total discounted revenue cannot be deemed "detailed," or constitute
19 reasonable "analysis."

20 **Q. WHAT QUALITATIVE REASONS DOES MR. QUINN PROVIDE FOR THE**
21 **COMPANY OFFERING DISCOUNTED RATES TO SELECT CUSTOMERS?**
22

23 A. Mr. Quinn claims that discounted rates are generally offered due to competitive
24 options specific to individual customers. The implication being that Equitable is unable
25 to compete for distribution service at full tariff rates. As provided on page 14 of his
26 direct testimony, Mr. Quinn offered three specific reasons as to why Equitable offers
27 discounted rates: (1) direct by-pass competition from pipelines and/or other LDC's; (2)

1 alternative fuel options; and, (3) economic development related issues such as industrial
2 competition and job retention factors.

3 **Q. WHY SHOULD REGULATORS BE CONCERNED ABOUT DISCOUNTED**
4 **RATES DUE TO COMPETITIVE FORCES?**

5
6 A. Regulators should be concerned about discounted rates for theoretical, public
7 interest, and practical reasons. From a theoretical standpoint, regulators should be
8 concerned about discounted rates due to the possibility of what is known as undue price
9 discrimination. Undue price discrimination usually occurs when a firm has monopoly
10 power over one group of customers yet is constrained by competitive forces for other
11 customers. This undue price discrimination concern is exacerbated when a regulated firm
12 seeks to shield its shareholders from the effects of competition by requiring captive
13 customers (in which there is monopoly power) to pay a premium (resulting from the
14 discounts offered to certain customers). In other words, regulators should have concerns
15 over the ability of a utility to price discriminate even when the utility is at risk for any
16 price discounts. This concern is heightened when captive ratepayers are asked to bear the
17 burden of any revenue shortfalls.

18 From a public interest, or public policy perspective, forcing captive customers to
19 pay for rate discount programs or allowances may not be desirable, or at the very least,
20 should be closely monitored simply due to the perceived unfairness across customers.
21 This unfairness concern stems from a captive customer paying a higher price for utility
22 service than an identical (or similar) customer simply because the captive (higher priced)
23 customer does not have a competitive alternative. To illustrate, suppose there are two
24 fertilizer factories served by the same utility. Suppose one factory is geographically
25 situated near another LDC utility, and that the other factory is a few miles away but does

1 not have access to alternative natural gas facilities; i.e., is captive to one LDC. It may
2 seem unfair and difficult to explain why the captive factory must pay more for natural gas
3 service due to its geographical location when the LDC's service area serves both fertilizer
4 factories. Indeed, due to the heavy reliance on natural gas, the captive fertilizer factory
5 may not be able to compete with the factory offered natural gas discounts. In fact, direct
6 competition between users need not be present for public policy concerns; i.e., it may be
7 unfair to allow price discrimination within a utility service area between two customers
8 that do not compete with each other, yet have similar natural gas requirements.

9 From a practical standpoint, regulators should be concerned about unverifiable
10 discounted LDC rates due to the potential lack of diligence of the LDC to maximize
11 revenue from discounted rates. This practical concern goes to prudence, actual need for
12 each discount, and assurances that every reasonable measure is taken to minimize
13 discounts when captive customers are requested to pay for these discounts. In this regard,
14 regulators should rely on the common saying "trust but verify."

15 **Q. BEFORE WE CONTINUE WITH THE SPECIFICS OF EQUITABLE'S**
16 **REQUEST FOR CAPTIVE RATEPAYERS TO BEAR THE FULL BURDEN OF**
17 **RATE DISCOUNTS, CAN YOU PROVIDE AN ESTIMATE OF THE**
18 **MAGNITUDE OF EQUITABLE'S REQUEST?**

19
20 **A.** Yes. Although I will discuss and present the details of discounted revenues later
21 in my testimony, Equitable's request is approximately \$22.7 million. Furthermore,
22 discounted rate customers actually pay on average about \$0.91/Mcf for delivery service
23 compared to a rate for similar captive customers of about \$2.39/Mcf. As such, the
24 average discount is about 62%.

1 Q. MR. WATKINS, DO YOU HAVE ANY CONCERNS REGARDING MR.
2 QUINN'S FIRST STATED REASON TO OFFER DISCOUNTED RATES, THAT
3 BEING DIRECT BY-PASS OPPORTUNITIES TO PIPELINES AND OTHER
4 DISTRIBUTION COMPANIES?
5

6 A. There is no doubt that gas on gas competition exists in western Pennsylvania.
7 However, a major concern I have is whether the discounts provided are truly justified.

8 Q. WHAT ARE YOUR SPECIFIC CONCERNS REGARDING MR. QUINN'S
9 SECOND REASON FOR OFFERING DISCOUNTS TO SELECTED
10 CUSTOMERS, THAT BEING ALTERNATIVE FUEL OPTIONS?
11

12 A. There is also no doubt that some industrial customers have the physical ability to
13 switch between fuel sources. These possible fuel source alternatives include natural gas,
14 propane, #2 oil, #6 oil, coal, and/or waste oil. However, most industrial customers will
15 pay a premium to use natural gas as their fuel source for several reasons. First, there is a
16 need for on-site storage for propane, oil, and coal. Although many industrial customers
17 may have some storage capacity on premises, it is often not nearly enough to meet all of
18 their energy needs and is used for emergency and interruptible situations. Second,
19 additional maintenance is often required when oil or coal is used as boiler fuel instead of
20 natural gas. Third, environmental emission constraints frequently play a role in the
21 ability to use certain fuels. Many industrials are limited in the amount of emissions
22 produced by their plants. Constant or continual use of coal or oil could exceed their
23 emissions allowances and, therefore, may not be feasible except for infrequent and short
24 periods of time.

25 Regardless of these constraints, I have conducted a quantitative analysis of the
26 cost differentials between natural gas, propane, and #2 oil. For purposes of the cost of
27 natural gas delivered to the Company's city gate, I have used Equitable's current

1 purchased gas rate as a surrogate for what transportation customers pay for gas delivered
2 to the Company's system. The purchased gas rate is currently \$14.45 per Mcf.

3 Recent #2 oil prices as reported by the U.S. Department of Energy, Energy
4 Information Administration are as follows:

5 Wholesale (NY Harbor):

6 10/03/08 \$2.982/gallon

7 09/01/08 \$3.125/gallon

8 Even though industrial customers in Pennsylvania likely cannot purchase oil at the
9 Harbor wholesale price, we can assume a price of \$3.00 per gallon as a point of
10 comparison with a heating value of 140,000 BTU per gallon, and assume equivalent
11 boiler efficiency as natural gas. Although I recognize that an MCF of natural gas is not
12 exactly equal to a Dth, this equates to an oil price of \$21.43 per Dth, which is almost
13 \$7.00 more than the benchmark price of gas to Equitable's city gate (\$14.45/MCF). This
14 means that there is room for \$7.00 in Equitable's distribution charges before #2 oil
15 becomes competitive with natural gas. I have not conducted a comparative analysis of
16 coal, as the price of this fuel source varies considerably from customer to customer.

17 A similar analysis was conducted for propane. The average U.S. wholesale price
18 of propane in which data is available (March 2008) was \$1.634 per gallon excluding
19 taxes. Using an industrial price of \$2.00 per gallon to recognize taxes and delivery costs,
20 and a heating value of 92,000 BTU per gallon equates to a propane price of \$21.74 per
21 Dth. This price of \$21.74 minus the benchmark cost of gas of \$14.45 equates to more
22 than \$7.00 per Dth available for gas distribution costs to these customers before propane
23 becomes competitive.

1 **Q. HOW DO THESE ALTERNATIVE FUEL PRICES PER DTH COMPARE WITH**
2 **EQUITABLE'S CURRENT COMMODITY CHARGES AND DISTRIBUTION**
3 **CHARGES?**

4
5 A. The current Rate GDS and DDS full tariff delivery charges are \$2.557 for small
6 C&I customers and \$2.360 for large customers. These full tariff amounts compare to the
7 approximate \$7.00 additional cost of oil and propane as an alternative fuel source.

8 It is hard to believe that #2 oil or propane is an effective competitor to Equitable's
9 natural gas customers. I do not know the viability of Equitable's gas customers using
10 coal as an alternative fuel source, and this may indeed be a competitive alternative to
11 some customers currently receiving natural gas discounts from Equitable. I simply do not
12 know with the data publicly available.

13 **Q. PLEASE EXPLAIN YOUR SPECIFIC CONCERNS REGARDING MR. QUINN'S**
14 **LAST REASON FOR OFFERING DISCOUNTS TO SELECTED CUSTOMERS,**
15 **THAT BEING ECONOMIC DEVELOPMENT RELATED ISSUES SUCH AS**
16 **INDUSTRIAL COMPETITION AND JOB RETENTION FACTORS.**

17
18 A. There are normally several factors considered in evaluating an economic
19 development project or proposal including: tax benefits that may be offered; community
20 revitalization; pollution control; zoning and local desirability of a particular project, etc.
21 whereas, Equitable is only concerned with the sale and distribution of gas.

22 **Q. REGARDLESS OF WHETHER EQUITABLE SHOULD OR SHOULD NOT**
23 **HAVE INCLUDED A DETAILED ANALYSIS OF RATE DISCOUNTS AS PART**
24 **OF ITS FILING, DID YOU SEEK TO INVESTIGATE YOUR CONCERNS**
25 **REGARDING DISCOUNTS OFFERED TO SELECTED CUSTOMERS?**

26
27 A. Yes.

28 **Q. PLEASE EXPLAIN.**

29 A. In late July, I asked a series of detailed data requests seeking information about
30 Equitable's rate discounts. By the middle of September I had not received any responses

1 to this inquiry. During about the third week of September, I participated in a conference
2 call with the Company, Office of Trial Staff, and OCA regarding this inquiry. During
3 this call, Equitable expressed serious concerns it had regarding the proprietary nature of
4 the information requested. Equitable was informed that I was not interested in names of
5 specific customers and that it was acceptable to eliminate this information or only
6 provide codes. Equitable then claimed that this was not acceptable because marketers
7 would know who customers are simply with consumption information provided.
8 Equitable further claimed that the OCA did not need such information as the rate
9 discounts do not affect the Residential class.

10 Equitable's last reason for not providing the requested information was that the
11 information was voluminous and a burden to produce. Given the fact that only about two
12 weeks remained before my direct testimony was due, there was little, if anything, that
13 could be analyzed in this short timeframe considering that Equitable's representations
14 were that the data was not organized in any reasonable fashion or available electronically.
15 Since it is the burden of the Company to justify whether such discounts are prudent
16 considering that Equitable seeks captive ratepayers to fund this preferential treatment at
17 no cost to shareholders, I can only conclude that Equitable has been unable or unwilling
18 to produce the information required to meet its burden.

19 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RATEMAKING**
20 **TREATMENT OF EQUITABLE'S RATE DISCOUNTS OFFERED TO**
21 **SELECTED CUSTOMERS?**

22
23 **A.** I recommend that Equitable's request for captive ratepayers to bear the burden of
24 this revenue shortfall be denied in its entirety unless and until Equitable meets its burden
25 of demonstrating that such discounts are fully justified and that recovery of such revenues

1 from remaining captive customers is just and reasonable and not unduly discriminatory.
2 This revenue adjustment increases the Company's future test year revenues at current
3 rates by \$22.791 million as provided in my Schedule GAW-7.

4 **Q. DO YOU HAVE ANY CONCLUDING COMMENTS REGARDING**
5 **EQUITABLE'S ARGUMENTS CONCERNING RATE DISCOUNTS?**

6
7 A. Subsequent to my decision to terminate further attempts to obtain information
8 required to investigate the reasonableness of Equitable's discounted rates, I discovered
9 the following requirements in Equitable's own tariff concerning Standards of Conduct:

10 If Equitable provides a distribution service discount, fee waiver or
11 rebate to its favored customers, or to the favored customers of its affiliated
12 natural gas supplier, Equitable shall offer the same distribution service
13 discount, fee waiver or rebate to other similarly situated customers. Offers
14 shall not be tied to any unrelated service, incentive or offer on behalf of
15 either Equitable or its affiliated natural gas supplier. A chronological log
16 shall be maintained showing the date, party, time and rationale for the
17 action. The chronological log shall be open for public inspection during
18 normal business hours.¹

19 Not only is Equitable required to maintain a log of information containing at least part of
20 the information I requested, this information is to be made available to the public at large.
21 Furthermore, the tariff requires that the same discounts must be offered to other similarly
22 situated customers. It is unclear whether "similarly situated" simply means customers
23 that have the ability to leave Equitable's system. It should be noted that as of October 7,
24 2008 the OCA has a Data Request outstanding specifically requesting this log.

¹ P.A.C. No. 22, Supplemental No. 18, First Revised Page No. 37, Item 7.

1 **Q. PLEASE EXPLAIN EQUITABLE'S PROPOSED NRG ENERGY RETAINAGE**
2 **DISCOUNT SURCHARGE.**

3
4 A. As noted by Mr. Quinn on Page 29 of his direct testimony, the Commission
5 approved a settlement in a 1307(f) proceeding (Docket No. R-00061295) that transferred
6 the discount for gas retainage offered to NRG Energy from Equitable PSC (gas cost) rates
7 to its base distribution rates. Equitable requests this transfer to be collected in the form of
8 a Rider (Rider C) surcharge which will vary each year and apply only to maximum rate
9 (captive) customers.

10 As I understand the Settlement in Docket No. R-00061295, the parties agreed to
11 transfer this discount from the PGC to base rates. However, the parties did not agree to a
12 moving target (Rider) within base rates that automatically adjusts from year to year.

13 The Company's automatic rate recovery of this NRG discount through a
14 surcharge should be rejected. This is not to imply that I object to the recognition of this
15 discount in base rates as agreed to by the parties, but rather the guaranteed recovery of
16 this discount through a surcharge. This discount should simply be reflected in base rates,
17 as agreed to in the settlement, without automatic adjustment.

18 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

19 A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

SCHEDULES TO THE
DIRECT TESTIMONY OF
GLENN A. WATKINS

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

NEGOTIATED REVENUE AND RATE STRUCTURE

OCTOBER 8, 2008

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINSVICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jul. 1995-Present	Vice President/Senior Economist, Technical Associates, Inc.
Mar. 1993-1995	Vice President/Senior Economist, C. W. Amos of Virginia
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

- A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

- B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

- C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.
- D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.
- E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

- A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.
- B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

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IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

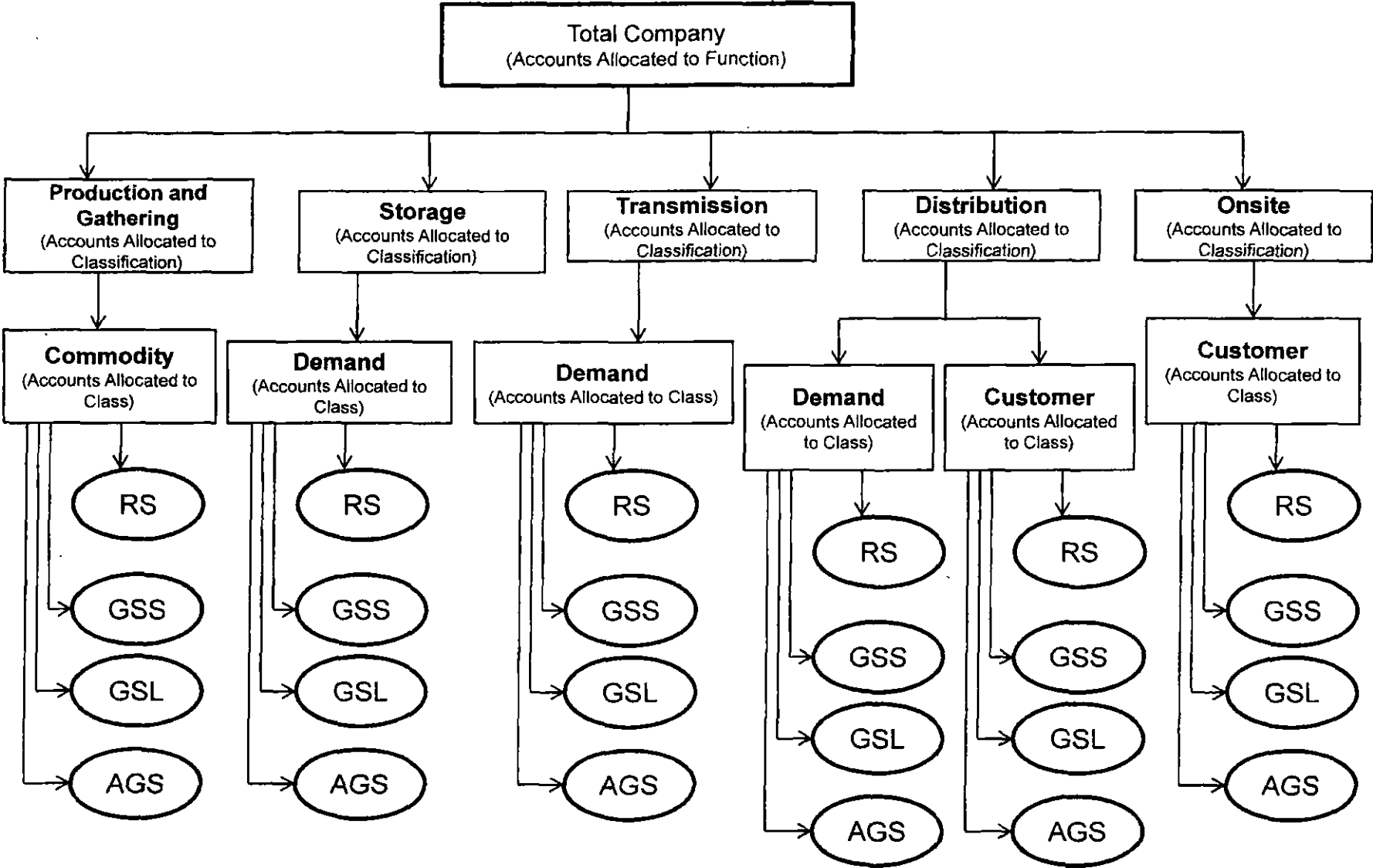
Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

Equitable Gas Company
CCOSS Structure

Schedule GAW - 2



Equitable Gas Company
Peak and Average (\$000)
(Summary)

Account Description	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
Revenue @ Current Rates	\$157,693	\$108,301	\$14,590	\$29,475	\$5,326
TOTAL OPERATING EXPENSES	\$105,496	\$77,950	\$6,406	\$15,171	\$5,970
TOTAL DEPRECIATION EXPENSES	\$23,471	\$15,756	\$1,207	\$4,836	\$1,673
TOTAL TAXES OTHER THAN INCOME	\$2,185	\$1,488	\$173	\$494	\$31
Total Expense Before Income Taxes	\$131,152	\$95,193	\$7,785	\$20,500	\$7,673
Earnings Before Interest & Taxes	\$26,541	\$13,108	\$6,805	\$8,975	-\$2,347
Interest @ Weighted Cost of Debt 2.91%	\$16,973	\$10,856	\$1,030	\$3,927	\$1,159
Earnings Before Tax	\$9,568	\$2,252	\$5,774	\$5,048	-\$3,506
Income Taxes @ effective Income Tax Rate (State + Fed) 45.44%	\$4,348	\$1,023	\$2,624	\$2,294	-\$1,593
Operating Income @ Current Rates	\$22,193	\$12,085	\$4,181	\$6,681	-\$754
Rate Base	\$583,253	\$373,067	\$35,412	\$134,950	\$39,824
RoR	3.81%	3.24%	11.81%	4.95%	-1.89%
Indexed RoR	100%	85%	310%	130%	-50%
Add Universal Service Increase to match costs included:					
Additional Revenue	16,865	16,865	0	0	0
Revenue Conversion Factor 1.7516	1.7516	1.7516	1.7516	1.7516	1.7516
Additional Income	9,628	9,628	0	0	0
Adjusted Operating Income	\$31,822	\$21,713	\$4,181	\$6,681	-\$754
Adjusted RoR with Universal Service increase:	5.46%	5.82%	11.81%	4.95%	-1.89%
Indexed RoR		106.68%	216.40%	90.74%	-34.69%
Required Income @ proposed Rate of Return 8.89%	\$51,852	\$33,166	\$3,148	\$11,997	\$3,540
Income Deficiency (Excess) after Universal Service increase:	\$20,030	\$11,453	-\$1,033	\$5,316	\$4,294
Conversion Factor	1.7516	1.7516	1.7516	1.7516	1.7516
Additional Revenue Required	\$35,085	\$20,060	-\$1,809	\$9,312	\$7,522
OCA Proposed Revenue Increase	\$51,950	\$37,243	\$1,320	\$5,865	\$7,522
Difference from Required Rev. Increase @ 8.89% ROR	\$0	\$318	\$3,129	-\$3,447	\$0
Conversion Factor	1.7516	1.7516	1.7516	1.7516	1.7516
Income Difference from Required	\$0	\$181	\$1,786	-\$1,868	\$0
Operating Income @ OCA Proposed Rates	\$51,852	\$33,348	\$4,934	\$10,029	\$3,540
ROR @ OCA Proposed Rates	8.89%	8.94%	13.93%	7.43%	8.89%
Indexed ROR @ OCA Proposed Rates	100%	101%	157%	84%	100%
Indexed ROR @ Current Rates	100%	85%	310%	130%	-50%

Equitable Gas Company
Peak and Average (\$000)
(Rate Base)

Acct. No.	Account Description	Alloc	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
Plant-in-Service							
	Intangible Plant						
	301 Organization	25	\$50	31	3	13	4
	303Lab Intangible Plant - Software - Labor	43	\$3,342	2,193	298	595	255
	303Cust Intangible Plant - Software - Customer	14	\$2,743	2,554	170	20	0
	303Plt Intangible Plant - Software - Plant	30	\$2,485	1,661	145	679	0
	303READI Miscellaneous Intangible Plant - READI	14	\$15,628	14,549	967	112	0
	Sub-total		\$24,248	\$20,988	\$1,582	\$1,419	\$259
	Production & Gathering Plant						
304-338 DA	Production and Gathering - Direct Assign.	Dir	\$28,445				28445
	Sub-total		\$28,445	\$0	\$0	\$0	\$28,445
	Storage Plant						
380-368	Storage Plant		\$0				
	Sub-total		\$0				
	Transmission Plant						
365-370	Transmission Plant	5	\$106	58	8	40	0
	367 Transmission - Mains	5	\$1,243	680	98	465	0
	Transmission Plant - Direct Assign.	Dir	\$14,171				14,171
365-370 DA							
367 DA	Transmission - Mains - Direct Assign.	Dir	16830				16,830
	Sub-total		\$32,350	\$738	\$107	\$504	\$31,001
	Distribution Plant						
	374 Land and Land Rights	5	\$1,893	1,036	150	708	0
374 DA	Land and Land Rights - Direct Assign.	dir	\$584			584	
	375 Structures and Improvements	5	\$2,111	1,155	167	789	0
	376 Mains	5	\$457,729	250,424	36,229	171,076	0
376 DA	Mains - Direct Assign.	dir	\$10,267			10,267	
	378 Meas. & Reg. Station Equip.- Gen.	5	\$16,126	8,823	1,276	6,027	0
378 DA	Meas. & Reg. Station Equip. - Direct Assig	Dir	\$1,469			1,469	
378odr	Meas. & Reg. Station Equip. - Odorization	5	\$447	245	35	167	0
	379 Meas. & Reg. Station Equip.- City Gate		\$0				
	380 Services	9	\$226,432	213,752	2,219	10,461	0
	381 Meters	7	\$17,775	12,344	1,822	3,610	0
	382 Meter Installations	7	\$9,208	6,394	944	1,870	0
	383 House Regulators	8	\$5,656	3,852	865	939	0
	384 House Regulators Installations	8	\$1,514	1,031	231	251	0
	385 Indust. Meas. & Reg. Station Equip.	dir	\$441			441	
	386 Property on Customers' Premises	24	\$15,838	14,395	356	1,086	0
	387 Other Equipment	Dir	\$324		324		
	Sub-total		\$767,794	\$513,449	\$44,619	\$209,726	\$0
	General Plant						
	389 Land and Land Rights	25	\$78	48	4	20	6
	390 Structures and Improvements	25	\$7,842	4,866	423	1,990	563
390 DA	Structures and Improvements - Direct Ass	Dir	\$67				67
	391 Office Furniture and Equipment	25	\$12,224	7,586	660	3,101	877
391 DA	Office Furniture and Equipment - Direct At	Dir	\$2				2
	392 Transportation Equipment	25	\$10,288	6,384	555	2,610	738
	393 Stores Equipment	25	\$47	29	3	12	3
	394 Tools and Garage Equipment	25	\$4,271	2,650	231	1,084	306
394 DA	Tools and Garage Equipment - Direct Ass	Dir	\$26				26
	395 Laboratory Equipment		\$0				
	396 Power Operated Equipment	25	\$3,155	1,958	170	800	226
	397 Communication Equipment	25	\$6,923	4,296	374	1,757	497
397 DA	Communication Equipment - Direct Assigr	Dir	\$6				6
	398 Misc. Equipment	25	\$32	20	2	8	2
398 DA	Misc. Equipment - Direct Assign.	Dir	156			156	
	Sub-total		\$45,117	\$27,838	\$2,421	\$11,538	\$3,319
TOTAL PLANT-IN-SERVICE			\$887,954	\$583,013	\$48,730	\$223,187	\$63,024

Equitable Gas Company
Peak and Average (\$000)
(Rate Base)

Acct. No.	Account Description	Alloc	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
Depreciation Reserve							
	108 Intangible Plant	35	\$8,236	7,129	537	482	88
	108.2 Production & Gathering Plant		\$0				
108.2 DA	Production & Gathering Plant - Direct Assi	Dir	\$8,153				8153
	108.3 Local Storage Plant		\$0				
	108.4 Transmission Plant	5	\$658	360	52	246	0
108.4 DA	Transmission Plant - Direct Assign.	Dir	\$11,969				11969
	109 Mains	5	\$130,432	71,359	10,324	48,749	0
	109 Services	9	\$83,524	78,847	819	3,859	0
	109 Meters	7	\$12,975	9,010	1,330	2,635	0
	109 Distr Other	29	\$13,987	9,394	1,037	3,557	0
	109 General Plant	25	\$19,396	12,036	1,047	4,921	1,392
108.8 DA	General Plant - Direct Assign.	Dir	21				21
	Sub-total		\$289,351	\$188,135	\$15,145	\$64,449	\$21,622
Other Rate Base Items							
	Materials and Supplies	25	\$887	550	48	225	64
	Current Gas Storage	6	\$75,176	64,110	7,382	3,684	0
	Prepayments	38	\$234	161	17	40	16
	Deferred Income Taxes - Depreciation	30	-\$102,288	-68,380	-5,948	-27,958	0
	Deferred Income Taxes - Direct Assign.	Dir	-\$2,423				-2423
	Deferred ITC	30	-\$4,903	-3,278	-285	-1,340	0
	Customer Deposits	18	-\$3,370	-2,776	-209	-386	0
	Sub-total		-\$36,885	-\$9,612	\$1,005	-\$25,735	-\$2,344
Total Rate Base Excluding Working Capital			\$571,918	\$365,268	\$34,590	\$133,004	\$39,058
	131 Working Capital	38	\$11,335	7,800	822	1,947	766
TOTAL RATE BASE			\$583,253	\$373,067	\$35,412	\$134,950	\$39,824

Equitable Gas Company Peak and Average (\$000) (Expenses)							
Acct. No.	Account Description	Alloc	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
O & M Expenses							
	Production & Gathering Expenses						
750-756	Operations Expense	Dir	\$1,043				\$1,043
761-765	Maintenance Expense	Dir	\$1,766				\$1,766
	Sub-total		\$2,809	\$0	\$0	\$0	\$2,809
	Other Gas Supply Expenses						
	801 Natural Gas Field Line Purchases		\$0				
	803 Natural Gas Transmission Line Purchases		\$0				
	804 Natural Gas City Gate Purchases		\$0				
	805 Other Natural Gas Purchases		\$0				
	807 Well Expenses - Purchased Gas		\$0				
	807 Maintenance of Purchased Gas Meas. Sta.		\$0				
	808 Gas Withdrawn from Storage		\$0				
	808 Gas Delivered to Storage		\$0				
	813 Other Gas Supply Expense	19	\$391	279	44	68	0
	Sub-total		\$391	\$279	\$44	\$68	\$0
	Natural Gas Storage						
	840 LNG Operating Exp Admin		\$0				
	850 Other Gas Purchases		\$0				
	Sub-total		\$0	\$0	\$0	\$0	\$0
	Transmission Expense						
856-863	Transmission Expense		\$0				
	Sub-total		\$0	\$0	\$0	\$0	\$0
	Distribution Expense						
	870 Oper Supv & Engineering	28	\$1,773	1,186	103	484	0
	871 Load Dispatching	1	\$112	53	9	50	0
	873 Compressor Station Fuel and Power		\$0				
	874 Mains & Service Expenses	31	\$5,088	3,255	270	1,346	217
	875 Meas & Reg Station General	32	\$100	50	7	42	0
	876 Meas & Reg Station Industrial		\$0				
	878 Meter & House Regulator Expense	33	\$6,062	4,193	685	1,184	0
	879 Customer Installation Expense	Dir	\$62	62			
	880 Other Expense - Safety and Enviro	39	\$632	402	48	175	6
	880 Other Expense	39	\$650	414	50	180	6
	881 Distribution Rents	28	\$602	403	35	164	0
	885 Maint Supervision & Engineering	28	\$885	592	51	242	0
	886 Maintenance of Structures and Imp	28	\$516	345	30	141	0
	887 Maint Mains	36	\$5,521	2,954	427	2,139	0
	889 Maint Meas & Reg Sta Gen	5	\$1,192	652	94	446	0
	891 Maint Meas & Reg Sta City Gate C	5	\$10	5	1	4	0
	892 Maint Services	9	\$663	626	6	31	0
	893 Maint Meters & House Reg	33	\$107	74	12	21	0
	894 Maint Other Equipment	28	\$67	45	4	18	0
	Sub-total		\$24,042	\$15,311	\$1,834	\$6,668	\$229
			\$27,242	\$16,690	\$1,878	\$6,736	\$3,038
Customer Accounts Expense							
	901 Customer Service - Administrative	20	\$225	209	14	2	0
	902 Meter Reading Expense	20	\$587	546	36	4	0
	903 Cust. Records & Collection Exp	20	\$10,270	9,561	636	74	0
	904 Uncollectible Accounts- Common	21	\$8,883	8,338	190	355	0
	904 Uncollectible Accounts- Univ. Ser.	Dir	\$16,167	16,167			
	905 Misc. Customer Accounts Expense		\$0				
	Sub-total		\$36,132	\$34,822	\$876	\$434	\$0
Customer Service & Information Expenses							
	907 Operation Supervision		\$0				
	908 Customer Assistance - Other Com	20	\$210	195	13	2	0
	908 Customer Assistance - Other Univ.	Dir	\$299	299			
	910 Other Customer Service & Informa	dir	\$698	698			
	911 Supervision		\$0				
	912 Demonstration	23	\$860	0	591	69	0
	913 Advertising Expense	23	\$24	0	22	2	0
	Sub-total		\$1,891	\$1,192	\$626	\$73	\$0
Total - Customer Accounts - Services				\$38,023	\$38,014	\$1,502	\$607
Total O&M Excluding A&G				\$65,265	\$51,604	\$3,380	\$7,242
							\$3,038

Equitable Gas Company
Peak and Average (\$000)
(Expenses)

Acct. No.	Account Description	Alloc	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
Administrative & General Expenses							
	Labor-Related						
	920 Administrative & General Salaries	43	\$5,940	3,898	530	1,058	454
	920 DA Administrative & General Salaries -	43	\$550	361	49	98	42
	921 Office Supplies & Expenses	43	\$817	536	73	146	62
	923 Outside Services Employed - Resic	43	\$180	118	16	32	14
	923I Outside Services Employed - Labo	43	\$3,637	2,387	324	648	278
	925 Labor Injuries & Damages	43	\$338	222	30	60	26
	926 Employee Pension & Benefits	43	\$5,725	3,757	511	1,020	437
	- 931 Rents	43	4,025	2,641	359	717	308
	Sub-total		\$21,212	\$13,920	\$1,892	\$3,778	\$1,621
	Plant-Related						
	924 Property Insurance	25	\$335	208	18	85	24
923p	Outside Services Employed - Plant	25	\$135	84	7	34	10
925Plant	Injuries and Damages	25	\$4,130	2,563	223	1,048	296
	932 Misc. Maintenance Expense	34	\$1,228	758	66	314	90
932 DA	Misc. Maintenance Expense - Direc	34	50	31	3	13	4
	Sub-total		\$5,878	\$3,843	\$317	\$1,494	\$424
	Other-Related						
	922 Administrative Expenses Transfe	40	-\$37	-25	-2	-7	-2
	923c Outside Services Employed-cust	40	\$5,083	3,397	316	1,027	343
923p-om	Outside Services Employed-plant-t	40	\$7,021	4,692	436	1,419	474
	923p-om DA Outside Services Employed-plant-t	40	\$200	134	12	40	13
	928 Regulatory Commission Expenses	40	\$517	345	32	105	35
	930.1 General Advertising Expense	40	\$201	134	12	41	14
	930.2 Miscellaneous General Expenses	40	\$156	104	10	32	11
	Sub-total		\$13,141	\$8,782	\$816	\$2,656	\$886
Total Administrative & General			40,231	28,346	3,025	7,829	2,931
Total Operating Expense (Excluding Depreciation)			\$108,496	\$77,560	\$8,408	\$16,171	\$6,970
Depreciation Expense							
	180Int Intangible Plant	35	\$2,439	2,111	159	143	26
	180ProdGth DA Production & Gathering Plant - Dir	26	\$631	0	0	0	631
	180Stor Local Storage Plant		\$0				
	180Trans Transmission Plant	27	\$9	0	0	0	9
	180Trans DA Transmission Plant - Direct Assign	Dir	\$704				\$704
	180Mains Mains (Distribution)	36	\$6,999	3,745	542	2,712	0
	180Services Services	9	\$5,815	5,489	57	269	0
	180Meters Meters	7	\$796	553	82	162	0
	180Dist Distr Other	29	\$2,003	1,345	148	509	0
	180Gen General Plant	34	\$4,071	2,512	218	1,041	300
	180Gen DA General Plant - Direct Assign.	Dir	\$4				\$4
	Adjustments		\$0				
TOTAL DEPRECIATION EXPENSES			\$23,471	\$16,768	\$1,207	\$4,836	\$1,673
Taxes							
	General Taxes						
	PA PUC Assessment	16	\$1,139	805	111	224	0
	Local Property Taxes	30	\$63	42	4	17	0
	Public Utility Realty Tax	30	\$519	347	30	142	0
	State Capital Stock Tax	41	\$447	286	27	103	31
	Miscellaneous Tax	1	\$17	8	1	8	0
	406 Sub-total		\$2,185	\$1,488	\$173	\$494	\$31
TOTAL TAXES OTHER THAN INCOME			\$2,185	\$1,488	\$173	\$494	\$31
INCOME TAXES							
	State Income Tax Expense		-\$1,009				
	Federal Income Tax Expense		\$5,363				
	Investment Tax Credit - Amortizatio	42	-\$6	-4	0	-1	0
TOTAL INCOME TAXES & ITC			\$4,348				
Total Tax Expense			2,163				
TOTAL EXPENSES			\$138,500				

Equitable Gas Company
Peak and Average (\$000)
(Salaries & Wages)

Acct. No.	Account Description	Alloc	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
Production and Gathering							
	Production and Gathering O&	26	1164	0	0	0	1,164
	Purchased Gas Expense		0				
	Other Gas Supply Expense		0				
	Sub Production		1164	0	0	0	1164
Storage							
	LNG Operating Exp Admin		0				
	Operating Exp Admin		0				
	Sub Storage		0	0	0	0	0
Transmission							
	Transmission Expenses		0				
	Sub Transmission		0	0	0	0	0
Distribution							
	Operation Supv & Engineerin	28	1251	837	73	342	0
	Load Dispatching	1	77	37	6	34	0
	Compressor Station Fuel and Power		0				
	Mains and Services Expense	31	1527	977	81	404	65
	Meas. & Reg. Station Expense	32	40	20	3	17	0
	Meas. & Reg. Station Expense Industrial		0				
	Meter & House Regulator Exp	33	2825	1,954	319	552	0
	Customer Installation Expense	Dir	6	6			
	Other Expenses - Safety and	39	172	110	13	48	2
	Other Expenses	39	177	113	14	49	2
	Maint. Supervision & Engineer	28	605	405	35	165	0
	Maintenance of Structures & I	28	166	111	10	45	0
	Maint. Of Mains	36	2262	1,210	175	876	0
	Maint Of Meas & Reg Station	5	608	333	48	227	0
	Maint of Meas & Reg Sta Exp	5	7	4	1	3	0
	Maint of Services	9	300	283	3	14	0
	Maint of Meters & House Reg	33	46	32	5	9	0
	Maintenance of Other Equipm	28	45	30	3	12	0
	Sub Distribution		10114	6459.76726	788.290009	2797.48	68.462713
Onsite							
	Customer Service - Administr	20	174	162	11	1	0
	Meter Reading Expenses	20	144	134	9	1	0
	Customer Records & Collecti	20	3828	3,564	237	27	0
	Operation Supervision		0				
	Customer Assist - Other	20	285	265	18	2	0
	Supervision		0				
	Demonstration	23	420	0	376	44	0
	Sub Onsite		4851	4124.97504	650.654084	75.370873	0
Total Salaries & Wages			16129	10584.7423	1438.94409	2872.8509	1232.4627

Equitable Gas Company
Peak and Average (\$000)
(Revenue)

Acct. No.	Account Description	Alloc	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
480-483	Sales and Transport Revenue		\$154,865	\$105,632	\$14,510	\$29,396	\$5,326
	Forfeited Discounts	21	\$1,558	1,462	33	62	0
	Miscellaneous Service Revenue	17	\$1,209	1,164	40	5	0
	Other Operating Revenue	16	\$61	43	6	12	0
TOTAL REVENUE			\$157,693	\$108,301	\$14,590	\$29,475	\$5,326

Equitable Gas Company
Peak and Average (\$000)
(Allocator Amounts)

Name	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
1 Gas_Deliveries	46,630,959	22,186,579	3,805,003	20,639,377	0
2 Gas_Deliver_w/AGS	61,075,112	22,186,579	3,805,003	20,639,377	14,444,153
3 Bills_All	3,084,066	2,871,066	190,884	22,116	0
4 Peak	637,309	393,250	48,715	195,344	0
5 Peak&Avg	1	0.5471	0.0792	0.3738	0.0000
6 Storage	1	0.8528	0.0982	0.0490	0.0000
7 Meter_Invest	1.0001	0.6945	0.1025	0.2031	0.0000
8 Account 383/384	1.0001	0.6811	0.1529	0.1661	0.0000
9 Service_Invest	1	0.9440	0.0098	0.0462	0.0000
10 AGS Direct	1	0.0000	0.0000	0.0000	1.0000
11 RS Direct	1	1.0000	0.0000	0.0000	0.0000
12 GSS Direct	1	0.0000	1.0000	0.0000	0.0000
13 GSL Direct	1	0.0000	0.0000	1.0000	0.0000
14 Cust_Avg	257,006	239,256	15,907	1,843	0
15 Delivery_Rev	154,864	105,632	14,510	29,396	5,326
16 Delivery_RevxAGS	149,538	105,632	14,510	29,396	0
17 Misc_Ser_Rev	1	0.9627	0.0334	0.0039	0.0000
18 Deposits	1	0.8236	0.0620	0.1144	0.0000
19 Account813	1	0.7135	0.1135	0.1730	0.0000
20 Cust_Avg	257,006	239,256	15,907	1,843	0
21 Account904-- common	8,883	8,338.0000	190.0000	355.0000	0.0000
22 Account910	1	1.0000	0.0000	0.0000	0.0000
23 Account911-916	1	0.0000	0.8962	0.1038	0.0000
24 Account386	1	0.9089	0.0225	0.0686	0.0000
25 Prod, Trans, & Dist Gross Plant	828,589	514,187	44,726	210,230	59,446
26 Prod, Plant	28,445	0	0	0	28,445
27 Trans Plant	32,350	738	107	504	31,001
28 Dist. Plant	767,794	513,449	44,619	209,726	0
29 Dist Plt Exc Mains, Services, Meters	43,926	29,500	3,255	11,170	0
30 Prod, Trans, & Dist Gross Plant-- Exc /	769,143	514,187	44,726	210,230	0
31 Trans & Dist Mains +Services Plt	726,778	464,913	38,555	192,309	31,001
32 Acct 378	18,042	9,067	1,312	7,663	0
33 Accts 381 - 384	34,153	23,621	3,862	6,671	0
34 General Plant	45,117	27,838	2,421	11,538	3,319
35 Intangible Plt	24,248	20,988	1,582	1,419	259
36 Dist Mains Plant	467,996	250,424	36,229	181,343	0
37 O&M Exc A&G Excl Univ. Service	48,101	34,440	3,380	7,242	3,038
38 Total O&M	88,332	60,786	6,406	15,171	5,970
39 Dist Expenses Exc acct 880	22,760	14,495	1,736	6,312	217
40 Avg of P,T,D Plt & O&M Exc A&G	1	0.668276641	0.062126541	0.202142954	0.067453864
41 Rate Base	583,253	373,067	35,412	134,950	39,824
42 Total Plant in Service	897,954	563,013	48,730	223,187	63,024
43 Total Salaries & Wages	16,129	10,585	1,439	2,873	1,232

Equitable Gas Company
Peak and Average (\$000)
(Allocator Percentage)

Name	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
1 Gas_Deliveries	100%	47.5791%	8.1598%	44.2611%	0.0000%
2 Gas_Deliver_w/AGS	100%	36.3267%	6.2300%	33.7934%	23.6498%
3 Bills_All	100%	93.0935%	6.1894%	0.7171%	0.0000%
4 Peak	100%	61.7048%	7.6439%	30.6514%	0.0000%
5 Peak&Avg	100%	54.7100%	7.9150%	37.3750%	0.0000%
6 Storage	100%	85.2800%	9.8200%	4.9000%	0.0000%
7 Meter_Invest	100%	69.4431%	10.2490%	20.3080%	0.0000%
8 Account 383/384	100%	68.1032%	15.2885%	16.6083%	0.0000%
9 Service_Invest	100%	94.4000%	0.9800%	4.6200%	0.0000%
10 AGS Direct	100%	0.0000%	0.0000%	0.0000%	100.0000%
11 RS Direct	100%	100.0000%	0.0000%	0.0000%	0.0000%
12 GSS Direct	100%	0.0000%	100.0000%	0.0000%	0.0000%
13 GSL Direct	100%	0.0000%	0.0000%	100.0000%	0.0000%
14 Cust_Avg	100%	93.0935%	6.1893%	0.7171%	0.0000%
15 Delivery_Rev	100%	68.2095%	9.3695%	18.9818%	3.4391%
16 Delivery_RevxAGS	100%	70.6389%	9.7032%	19.6579%	0.0000%
17 Misc_Ser_Rev	100%	96.2700%	3.3400%	0.3900%	0.0000%
18 Deposits	100%	82.3600%	6.2000%	11.4400%	0.0000%
19 Account813	100%	71.3500%	11.3500%	17.3000%	0.0000%
20 Cust_Avg	100%	93.0935%	6.1893%	0.7171%	0.0000%
21 Account904-- common	100%	93.8647%	2.1389%	3.9964%	0.0000%
22 Account910	100%	100.0000%	0.0000%	0.0000%	0.0000%
23 Account911-916	100%	0.0000%	89.6200%	10.3800%	0.0000%
24 Account386	100%	90.8900%	2.2500%	6.8600%	0.0000%
25 Prod, Trans, & Dist Gross Plant	100%	62.0557%	5.3978%	25.3721%	7.1744%
26 Prod, Plant	100%	0.0000%	0.0000%	0.0000%	100.0000%
27 Trans Plant	100%	2.2814%	0.3301%	1.5585%	95.8300%
28 Dist. Plant	100%	66.8733%	5.8113%	27.3154%	0.0000%
29 Dist Plt Exc Mains, Services, Meters	100%	67.1588%	7.4110%	25.4302%	0.0000%
30 Prod, Trans, & Dist Gross Plant-- Exc	100%	66.8519%	5.8150%	27.3330%	0.0000%
31 Trans & Dist Mains +Services Plt	100%	63.9691%	5.3049%	26.4604%	4.2655%
32 Acct 378	100%	50.2555%	7.2706%	42.4740%	0.0000%
33 Accts 381 - 384	100%	69.1618%	11.3070%	19.5313%	0.0000%
34 General Plant	100%	61.7023%	5.3671%	25.5733%	7.3574%
35 Intangible Plt	100%	86.5544%	6.5259%	5.8517%	1.0680%
36 Dist Mains Plant	100%	53.5098%	7.7414%	38.7489%	0.0000%
37 O&M Exc A&G Excl Univ. Service	100%	71.5996%	7.0275%	15.0565%	6.3164%
38 Total O&M	100%	68.8149%	7.2522%	17.1748%	6.7581%
39 Dist Expenses Exc acct 880	100%	63.6845%	7.6284%	27.7336%	0.9536%
40 Avg of P,T,D Plt & O&M Exc A&G	100%	66.8277%	6.2127%	20.2143%	6.7454%
41 Rate Base	100%	63.9631%	6.0714%	23.1375%	6.8280%
42 Total Plant in Service	100%	62.6995%	5.4267%	24.8551%	7.0187%
43 Total Salaries & Wages	100%	65.6255%	8.9215%	17.8117%	7.6413%

**EQUITABLE GAS COMPANY
OCA PROPOSED CUSTOMER CLASS REVENUE
INCREASE AT COMPANY'S OVERALL INCREASE
(\$000)**

	(1)	(2)	(3)	(4)	(5)	(6)
	Revenue Increase					
	Universal			Service Fund		
Class	Current Oper. Revenue <u>1/</u>	Margin	Percent (2) ÷ (1)	Total (2) + (4)	Percent (5) ÷ (1)	
RS	\$108,258	\$20,378 <u>2/</u>	18.8%	\$16,865 <u>4/</u>	\$37,243	34.4%
GSS	14,584	1,320 <u>2/</u>	9.1%	--	\$1,320	9.1%
GSL	29,463	5,865 <u>2/</u>	19.9%	--	\$5,865	19.9%
AGS	5,326	7,522 <u>3/</u>	141.2%	--	7,522	141.2%
TOTAL	\$157,631	\$35,085	22.3%	\$16,865	\$51,950	33.0%

1/ Per Company Exhibit IV, Item §53.53 IV B-1(B).

2/ Calculated as follows:

(1) End User LDC Current Revenue	\$152,305	<u>a/</u>	\$152,305
(2) End User LDC Revenue Increase	\$27,563	<u>b/</u>	\$27,563
(3) Revenue Increase Percent: (2) ÷ (1)	18.1%		
(4) GSS Increase At 50% of (3)	\$1,320	<u>c/</u>	
(5) GSL Increase At 110% of (3)	\$5,865	<u>c/</u>	
(6) RS Increase At Residual	\$20,378	<u>c/</u>	

<u>a/</u> Current Revenue:	RS	\$108,258
	GSS	14,584
	GSL	29,463
		<u>\$152,305</u>

<u>b/</u> LDC Revenue Increase:	Total	\$51,950
	Less USF	16,865
	AGS	7,522
		<u>\$27,563</u>

c/ Revenue Increase: $\$27,563 \div \$152,305 = 18.1\%$

GSS Increase: $50\% \times 18.1\% \times \$14,584 = \$1,320$

GSL Increase: $110\% \times 18.1\% \times \$29,463 = \$5,865$

RS Increase: $\$27,563 - \$1,320 - \$5,865 = \$20,378$

3/ Revenue increase reflects amount needed to bring class to full cost of service level based on CCOSS in Schedule GAW - 3.

4/ Per Equitable witness Quinn Direct Testimony, Page 16.

Equitable Gas Company
Determination of RS Customer Costs
(\$000)

Gross Plant	
Services	\$213,752
Meters	\$12,344
Meter Installations	\$6,394
House Regulators	\$3,852
House Regulator Installations	\$1,031
Total Gross Plant	\$237,373
Depreciation Reserve	
Services	\$78,847
Meters	\$9,010
Meter Installations	\$2,340 1/
House Regulators	\$1,410 1/
House Regulator Installations	\$377 1/
Total Depreciation Reserve	\$91,984
Total Net Plant	\$145,389
Operation & Maintenance Expenses:	
Oper Meter & House Reg	\$4,193
Oper Customer Install Exp	\$62
Maint Services	\$626
Maint Meters & House Reg	\$74
Meter Reading Expense	\$546
Cust. Records & Collection Exp.	\$9,561
Total O & M Expenses	\$15,062
Depreciation Expense	
Services	\$5,489
Meters	\$553
Meter Installations	\$335 2/
House Regulators	\$202 2/
House Regulator Installations	\$54 2/
Total Depreciation Expense	\$6,633
Revenue Requirement	
Interest	\$4,478
Equity return	\$6,355
Income Tax	\$5,189
Revenue For Return	\$16,022
O & M Expenses	\$15,062
Depreciation Expense	\$6,633
Total Customer Revenue Requirement	\$37,717
 Number of Bills	 2,871,066
 Monthly Cost Per Customer	 \$13.14

Cost of Capital

	PCT	Cost	WGHT Cost
Debt	53.00%	5.81%	3.08%
Preferred	0.00%	0.00%	0.00%
Common	47.00%	9.30%	4.37%
Total	100.00%		7.45%

1/	Plant-in-Service	Perc.	Dep Res
Meter Installations	6,394	24.91%	2,339.72
House Regulators	3,852	15.00%	1,409.54
House Regulator Installations	1,031	4.02%	377.27
Property on Customer Premises	14395	56.07%	5,267.48
Total	25672	100.00%	9,394

2/	Plant-in-Service	Perc.	Dep Res
Meter Installations	6,394	24.91%	334.99
House Regulators	3,852	15.00%	201.81
House Regulator Installations	1,031	4.02%	54.02
Property on Customer Premises	14395	56.07%	754.18
Total	25672	100.00%	1345

Schedule GAW-6

**PENNSYLVANIA NATURAL GAS COMPANIES
MONTHLY RESIDENTIAL CUSTOMER CHARGES**

Company	Monthly Customer Charge	Rate Effective Date
Sergeant Gas Company	\$2.75	11/01/06
Pike County Light & Power Company	\$5.00	09/01/06
North East Heat & Light Co.	\$5.47	11/01/06
Philadelphia Electric Company (PECO/Exelon Company)	\$7.20	12/01/07
UGI Utilities Inc.	\$8.55	10/01/01
Valley Energy	\$8.64	09/01/08
Columbia Gas of Pennsylvania, Inc.	\$10.81	07/01/08
Dominion Peoples (People's Natural Gas Company)	\$11.00	07/01/08
Equitable Gas Company	\$11.65	07/01/08
UGI Penn Natural Gas Inc.	\$11.75	03/01/08
National Fuel Gas Distribution Corporation	\$12.00	09/01/08
Philadelphia Gas Works (PGW)	\$12.00	09/01/08
PPL Utilities (North Penn Gas, Penn Fuel Gas)	\$12.00	09/01/08
T.W. Phillips Gas & Oil Company	\$12.50	08/01/08

**EQUITABLE GAS COMPANY
DISCOUNTED RATE REVENUES**

<u>Rate Schedule</u>	<u>Discounted Revenue</u>	
GDS	\$10,359,775	<u>1/</u>
DDS	\$12,431,130	<u>2/</u>
TOTAL	\$22,790,905	

1/ Per Page 2.
2/ Per Page 3.

EQUITABLE GAS COMPANY
FUTURE TY 12/31/08

Rate GDS - General Delivery Service

I. Negotiated Deliveries	
(1) Volumes MCF)	8,538,933
(2) Revenues	\$10,054,201
(3) Average Rate Per Mcf: (2)/(3)	1.17745
II. Tariffed Deliveries	
(1) Volumes (Mcf)	
(a) Small C&I	727,769
(b) Large C&I	3,943,426
(c) Total: (a) + (b)	4,671,195
(2) Revenues	
(a) Small C&I	\$1,860,905
(b) Large C&I	\$9,306,485
(c) Total: (a) + (b)	\$11,167,390
(3) Average Rate Per Mcf: (2c)/(1c)	2.39069
III. Forgone Revenues	
(1) Volumes (Mcf)	8,538,933
(2) Average Rate Per Mcf Difference: II(3) - I(3)	1.21324
(3) Revenue Discount: (1) x (2)	\$10,359,761

Source: Equitable Gas Company Exhibit III-20, Sheet 5.

EQUITABLE GAS COMPANY
FUTURE TY 12/31/08

Rate DDS - Daily Delivery Service - Industrial

I. Negotiated Deliveries	
(1) Volumes MCF)	6,995,567
(2) Revenues	\$4,078,409
(3) Average Rate Per Mcf: (2)/(3)	0.58300
II. Tariffed Deliveries	
(1) Volumes MCF)	0
(2) Revenues	\$0
(3) Revenue (Rate) Per MCF	\$2.557/\$2.360
III. Forgone Revenues	
(1) Volumes (Mcf)	6,995,567
(2) Average Rate Per Mcf: I(3)	0.58300
(3) Tariffed Revenue Per Mcf: II(3)	2.36000
(4) Revenue Per Mcf Difference: (3) - (2)	1.77700
(3) Revenues: (1) x (2)	\$12,431,129

Source: Equitable Gas Company Exhibit III-20, Sheet 5.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08

HB6, PA

R/S

Pennsylvania Public Utility Commission,

v.

Equitable Gas Company

Docket No. R-2008-2029325, et al

Independent Oil and Gas Association of
Pennsylvania

v.

Equitable Gas Company

C-20066800

REBUTTAL TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

OCTOBER 31, 2008

RECEIVED
2008 OCT 31 PM 1:31
SECRETARY OF THE PENNSYLVANIA
PUBLIC UTILITY COMMISSION

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Glenn A. Watkins and my business address is 1051 East Cary Street,
3 Suite 601, Richmond, Virginia, 23219.

4 **Q. HAVE YOU PREVIOUSLY PRE-FILED TESTIMONY IN THIS PROCEEDING?**

5 A. Yes. I pre-filed direct testimony on October 8, 2008 which has been identified as
6 OCA Statement No. 3.

7 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

8 A. I will respond and offer comments to the direct testimony of OSBA witness Brian
9 Kalcic and IOGA witness Diane Meyer Burgraff.

10 **Q. DID OSBA WITNESS BRIAN KALCIC CONDUCT A CLASS COST OF**
11 **SERVICE STUDY (“CCOSS”) FOR PURPOSES OF THIS PROCEEDING?**

12 A. No.

13 **Q. DOES MR. KALCIC SUPPORT SPECIFIC CCOSS RESULTS IN HIS DIRECT**
14 **TESTIMONY?**

15 A. Yes.

16 **Q. DOES MR. KALCIC USE THESE CCOSS AS THE BASIS FOR HIS CLASS**
17 **REVENUE ALLOCATIONS?**

18 A. Yes.

19 **Q. PLEASE EXPLAIN THE CCOSS RESULTS THAT MR. KALCIC SUPPORTS IN**
20 **THIS CASE.**

21 A. As indicated earlier, Mr. Kalcic did not conduct his own CCOSS for this case, but
22 instead, relied upon Equitable to run its computer model utilizing alternative

assumptions. The alternative assumptions requested by Mr. Kalcic in OSBA data request II-4 were as follows:

- a. Eliminate the customer component of distribution mains (as in OSBA-I-5);
- b. Directly assign all of the Company's CAP costs to the Residential class (per the Company's response to OSBA-I-4);
- c. Remove the negotiated delivery service revenues identified in OSBA-II-3 from the applicable customer classes' delivery revenues that are shown on Sheet 8, line 178 of the referenced cost study, and allocate the Company's total negotiated delivery service revenues back to all rate classes based upon total cost of service; and
- d. Remove the associated negotiated delivery service volumes identified in OSBA-II-3 from the applicable customer classes' external allocation factors shown in Item 53.53 IV-B-3(A), and adjust the affected customer classes' external peak demand allocation factor to reflect the reduced volumes (i.e., class size).

Q. DO YOU HAVE CONCERNS REGARDING MR. KALCIC'S RELIANCE ON EQUITABLE'S ANALYSIS?

A. Yes.

Q. DO YOU KNOW IF MR. KALCIC CAN ATTEST TO THE ACCURACY AND REASONABLENESS OF EQUITABLE'S MODEL AND ANALYSIS?

A. I cannot say for sure, but I do know that Equitable would not provide its computer model to the various parties in this case. I can also tell you from my own experience in evaluating Equitable's computer model, that it would be virtually impossible to verify the

1 model without the computerized model itself, or by replicating Equitable's results using a
2 model that you know for certain is reliable, accurate and reasonable.

3 **Q. AM I CORRECT THAT YOU DISCOVERED ERRORS IN EQUITABLE'S**
4 **CCOSS MODEL?**

5 A. Yes. I discussed these errors in my direct testimony. One error involved the
6 assignment of certain Universal Service Fund costs and the other involved a significant
7 mathematical accounting error in the determination and assignment of income taxes.

8 **Q. DID MR. KALCIC REQUEST EQUITABLE TO RERUN ITS CCOSS MODEL**
9 **AND ATTEMPT TO CORRECT THE ERROR CONCERNING THE**
10 **ASSIGNMENT OF UNIVERSAL SERVICE COSTS.**

11 A. Yes.

12 **Q. DO YOU HAVE ANY WAY OF REALISTICALLY KNOWING IF**
13 **EQUITABLE'S MODEL WAS CORRECTED TO REFLECT THE**
14 **COMPOUNDING RAMIFICATIONS OF THIS CHANGE?**

15 A. No.

16 **Q. WOULD MR. KALCIC HAVE ANY WAY OF KNOWING IF EQUITABLE**
17 **MADE ALL OF THE CORRECTIONS NECESSARY TO REFLECT THE**
18 **COMPOUNDING RAMIFICATIONS OF THIS CHANGE.**

19 A. I cannot say for certain. But to do so would require a complete understanding of
20 the calculations embedded in the Company's CCOSS model.

1 **Q. DO YOU KNOW IF THE EQUITABLE COMPUTER RUN CONDUCTED BY**
2 **EQUITABLE AND RELIED UPON BY MR. KALCIC ALSO CONTAINS THE**
3 **SAME INCOME TAX ERROR YOU IDENTIFIED IN YOUR DIRECT**
4 **TESTIMONY?**

5 A. Yes. The CCOSS results provided in response to OSBA data request II-4 (i.e., the
6 results Mr. Kalcic relied upon) contain the same income tax error as discussed in my
7 direct testimony. This error can easily be verified by comparing the effective income tax
8 rates of the various classes in the summary data provided on the first page of the
9 attachment to OSBA II-4. Whereas, the Total Company effective income tax rate is
10 calculated to be 16.38%, the effective tax rate to the Residential class is 21.98% and the
11 effective tax rate to the GSL class is 7.50%. In other words, the same error is present in
12 this model run performed by Equitable and used by Mr. Kalcic.

13 **Q. NOT WITHSTANDING THE ERRORS YOU HAVE IDENTIFIED IN THE**
14 **COMPANY'S CCOSS MODEL, DO YOU HAVE OTHER CONCERNS**
15 **REGARDING MR. KALCIC'S RELIANCE ON A COMPUTER RUN**
16 **PERFORMED BY EQUITABLE IN WHICH MR. KALCIC HAD NO CONTROL**
17 **OR SUPERVISION?**

18 A. Yes.

19 **Q. PLEASE EXPLAIN.**

20 A. Mr. Kalcic's request required interpretation and informed judgment in order to
21 comply with the request. As such, and as evident from Mr. Kalcic's own direct testimony
22 on Page 10 lines 8 through 22, misunderstandings are possible and indeed did occur.

1 A major requirement in OSBA data request II-4 was for Equitable to remove the
2 delivery volumes and maximum day demands for all negotiated rate customers within the
3 requested computer run. It was represented by Equitable to Trial Staff and the OCA in a
4 telephone conversation (in which I participated) that there are over 800 customers on the
5 Equitable system with negotiated rates. There is absolutely no way of knowing if the
6 assumptions and procedures used by Equitable to comply with OSBA's request were
7 correct, accurate, or even reasonable. This is particularly troubling as the elimination of
8 negotiated rate customers' loads would require the estimation of a large group of
9 customers' peak design day demands. At the very best, even if these demands are
10 somehow known for all 800 customers, the procedures utilized to estimate these demands
11 are not known by anyone other than the individual making such calculations.

12 To compound the problem, the peak day demands in question are not actual
13 demands, but estimated design day demands. There is absolutely no way that Mr. Kalcic,
14 me, or any party can verify the reasonableness and accuracy of Equitable's assumptions
15 and procedures to eliminate the estimated design day demands for a group of negotiated
16 rate customers.

1 **Q. DO YOU HAVE ANY DISAGREEMENTS WITH MR. KALCIC'S PROPOSAL**
2 **TO SPREAD DELIVERY REVENUES COLLECTED FROM NEGOTIATED**
3 **RATE CUSTOMERS TO ALL CUSTOMER CLASSES AND ALSO TO REMOVE**
4 **THE USAGE CHARACTERISTICS OF THESE NEGOTIATED RATE**
5 **CUSTOMERS FROM THE COSS?**

6 **A.** Yes. Mr. Kalcic's proposal would be reasonable if he consistently applied the
7 same logic and treated all costs in a similar fashion, but he does not. The underlying
8 logic behind Mr. Kalcic's proposal is that all customer classes should share in the cost
9 burden of negotiated rate customer discounts; i.e., the class in which negotiated rate
10 customer reside should not be solely responsible for revenue deficiencies that result from
11 discounted rates. As such, even though many customers (including the entire residential
12 class) do not qualify for discounted rates, and therefore, receive no direct benefits from
13 *the practice of negotiated rates, Mr. Kalcic assigns this discounted rate cost responsibility*
14 to all classes. This treatment is in stark contrast to the OSBA position and the
15 Commission findings and policy regarding Universal Service costs (also known as
16 Customer Assistance Program ("CAP") costs). This Commission has ruled on several
17 occasions that CAP costs should be the sole responsibility of the Residential class
18 *because Residential customers are the only class to receive direct benefits from the CAP*
19 program; i.e., Commercial and Industrial customers are not eligible for CAP discounts.
20 Although I disagree with the Commission's policy regarding the assignment of CAP
21 costs only to the Residential class, a fair and consistent treatment should also be applied
22 to similar situations. It is my understanding that Residential customers are not eligible
23 for discounted rates due to competition, alternative fuel options, or threat of bypass. This

1 is the exact same comparison as the argument made by the OSBA in numerous cases as
2 to why Commercial customers should not bear cost responsibility for CAP costs. That is,
3 the OSBA has argued that because Commercial customers are not eligible for CAP
4 discounts, they should bear no cost responsibility for CAP costs. This Commission has
5 agreed with OSBA's rationale in several cases relating to CAP cost. In short, Mr. Kalcic
6 is asking the Commission to spread costs resulting from non-Residential discounts to all
7 classes (primarily the Residential class), but does not expect all classes to share in the
8 costs of discounts resulting from CAP programs.

9 **Q. MR. WATKINS, DO ALL CAPTIVE RATE CUSTOMERS REAP INDIRECT**
10 **BENEFITS FROM NEGOTIATED RATE CUSTOMERS REMAINING ON**
11 **EQUITABLE'S SYSTEM?**

12 A. Only under the current state of affairs is this true. It is also true that all customers
13 indirectly benefit from any other class being part of the Equitable system regardless of
14 whether a customer is captive or not. That is, a fundamental principle of a utility system
15 is the benefits of economies of scale and that all customers benefit from cost
16 contributions made by other customers. However, herein lies the fundamental problem of
17 allowing price discrimination to those with the ability to use a competing LDC, and the
18 perception that discounted rates provide benefits to all ratepayers.

19 There have been numerous contentions that negotiated rate customers provide
20 some benefit to all captive customers by contributing somewhat to costs. These
21 contentions have led to a fear that competitive customers will leave an LDC system.
22 While it is true that under the current system, some customers do have the ability to leave
23 the Equitable system, their alternative is usually another LDC, say LDC "X". When

1 LDC "X" is in question, a reciprocal fear is imposed that customers will leave LDC
2 "X's" system and move to Equitable. As I indicated in my direct testimony, this issue of
3 allowing competition across LDC's is a zero sum game; i.e., these customers will not
4 forego the use of natural gas but simply shift from one LDC to another. The end result is
5 that captive rate customers are left responsible to pay for this so-called benefit of
6 retaining negotiated rate customers. Equitable's captive ratepayers see no benefit under
7 this system and neither do LDC "X's" customers. Indeed, the current practice only
8 results in higher rates to captive ratepayers of both companies. While it may appear that
9 captive customers who do not qualify for discounted rates indirectly benefit from the
10 customers staying on the Equitable system, we see that in reality, there is a significant
11 cost to captive ratepayers as a result of LDC competition in Pennsylvania.

12 **Q. DO YOU HAVE ANY OTHER COMMENTS CONCERNING CCOSS AS THEY**
13 **RELATE TO MR. KALCIC'S DIRECT TESTIMONY.**

14 A. Yes. Mr. Kalcic's supported CCOSS is based on the Peak Responsibility method.
15 I fully discuss this method in my direct testimony at pages 8 and 9 and explain there why
16 this method is not an appropriate method to assign costs.

17 **Q. DOES MR. KALCIC'S CCOSS PROVIDE A RELIABLE GUIDE AS TO THE**
18 **COSTS TO SERVE CUSTOMER CLASSES?**

19 A. No.

20 **Q. DO YOU HAVE ANY COMMENTS REGARDING MR. KALCIC'S PROPOSED**
21 **CLASS REVENUE ALLOCATIONS?**

22 A. Yes. Mr. Kalcic's Class revenue allocation proposal is driven by, and is a direct
23 result of his sponsored CCOSS results. I have already discussed my CCOSS concerns.

1 **Q. PLEASE COMMENT ON THE CONCEPTS OF MR. KALCIC'S FDR**
2 **MECHANISM.**

3 A. Whether intentional or not, Mr. Kalcic's First Dollar Relief ("FDR") mechanism
4 leaves a first impression that he is accepting Equitable's proposed revenue allocation but
5 makes modifications only to the incremental difference between what the Company
6 originally requested as an overall increase in revenue and what the Commission
7 ultimately authorizes. In all realistic likelihood, Mr. Kalcic's proposal would result in a
8 dramatically different revenue increase allocation than that proposed by Equitable.
9 Although no one knows what overall increase will be authorized by the Commission at
10 this point, I believe it is safe to assume Equitable will not receive every dollar it is
11 requesting. Indeed, various parties are proposing significant rate of return and revenue
12 requirement adjustments in this case. To illustrate how different Mr. Kalcic's revenue
13 allocation is from the Company's proposal, consider a reduction of only \$2.38 million
14 from that requested by Equitable. Under Mr. Kalcic's proposal, the GSS class would
15 receive 0.0% increase, the RS class would receive an increase of 37.9% and the GSL
16 class would incur a 6.8% increase. In my view such a revenue increase distribution is
17 materially different than that proposed by Equitable.

18 The most important concern I have with Mr. Kalcic's FDR mechanism is that it is
19 entirely dependent on specific CCOSS results. In my view, the disadvantages of Mr.
20 Kalcic's FDR mechanism are much more far reaching than he implies.

21 Remembering that Mr. Kalcic's FDR is based upon a CCOSS that he did not
22 conduct or supervise, is based on a CCOSS with known errors, and is based on a CCOSS
23 using a methodology not favored by this Commission, Mr. Kalcic provides no basis for

1 adjusting his FDR amounts should the Commission deviate in any way from his favored
2 CCOSS results provided in response to a data request.

3 As discussed previously in this testimony, and demonstrated in my direct
4 testimony, seemingly minor differences in allocation approaches can (and do) have
5 profound impacts on class rates of return. Mr. Kalcic's FDR mechanism as presented in
6 this case does not provide for changes in CCOSS results, either in direct or in absolute
7 terms. Moreover absolute mechanical reliance on a single CCOSS results do not comport
8 with reasoned and accepted ratemaking. As I indicated in my direct testimony, CCOSS
9 should certainly be considered in establishing class revenue responsibility, but they
10 should be one of many tools used in this important decision.

11 **Q. DO YOU HAVE ANY COMMENTS REGARDING THE DIRECT TESTIMONY**
12 **OF DIANE MEYER BURGRAFF?**

13 A. Yes. Ms. Burgraff's testimony brings up questions as to whether Equitable's
14 gathering system is used primarily by, and for the benefit of, producers to gather natural
15 gas produced in local wells.

16 I have accepted Equitable's assertion that gathering facilities only serve AGS
17 customers and its direct assignment of gathering facilities to rate AGS customers in my
18 proposed CCOSS. I will need to evaluate Equitable's response to Ms. Burgraff's
19 allegations that the gathering system is actually part of the Company's LDC system
20 before I can render an opinion regarding Ms. Burgraff's concerns.

21 **Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?**

22 A. Yes.

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11/19/08
HBC, PA
R/S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,

v.

Equitable Gas Company

Docket No. R-2008-2029325, et al

Independent Oil and Gas Association of
Pennsylvania

v.

Equitable Gas Company

C-20066800

SURREBUTTAL TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

NOVEMBER 14, 2008

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1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Glenn A. Watkins and my business address is 1051 East Cary Street,
3 Suite 601, Richmond, Virginia, 23219.

4 **Q. HAVE YOU PREVIOUSLY PRE-FILED TESTIMONY IN THIS PROCEEDING?**

5 A. Yes. I pre-filed direct testimony on October 8, 2008 and rebuttal testimony on
6 October 31, 2008 which has been identified as OCA Statement No. 3.

7 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

8 A. I will respond and offer comments to the rebuttal testimonies of Equitable witness
9 Quinn, IOGA witness Burgraff, and OSBA witness Kalcic.

10 **Q. PLEASE COMMENT ON THE REBUTTAL TESTIMONY OF EQUITABLE**
11 **WITNESS JOHN QUINN AS IT RELATES TO NEGOTIATED, DISCOUNTED**
12 **RATES.**

13 A. Mr. Quinn's rebuttal testimony does not directly address the issue at hand to a
14 large extent. In this regard, Mr. Quinn's rebuttal testimony on this subject provides a
15 host of legal arguments that I will not address, as well as assertions that the OCA and I
16 are not treating Equitable fairly compared to other LDC's in the Commonwealth. I also
17 will not address these attempts to divert attention from Equitable Gas and the issues
18 before the Commission in this proceeding.

19 Equitable's witnesses further attempt to cloud the issue by claiming that the rates
20 paid by certain customers are not "discounted" rates, but rather "negotiated" rates. While
21 it is obvious that the distinction is merely a matter of semantics, I will refer the Company
22 and the Commission to Equitable's own Tariff Supplement No. 18, First Revised page
23 No. 36, Item 7), regarding acceptable business practices:

1 “If Equitable provides a distribution service **discount, fee waiver or**
2 **rebate** to its **favored customers**, or to the **favored customers** of its
3 affiliated natural gas supplier, Equitable shall offer the same distribution
4 service **discount, fee waiver or rebate** to other similarly situated
5 customers.”
6 **[Emphasis added].**

7
8 It is clear, from common sense as well as Equitable’s own tariff, that my reference to the
9 rates and prices in question as “discounts” is appropriate and accurate.

10 **Q. FOR THE RECORD, PLEASE CLARIFY YOUR POSITION REGARDING**
11 **EQUITABLE’S PRACTICE TO OFFER NEGOTIATED RATES TO CERTAIN**
12 **CUSTOMERS.**

13 A. It is not my position or testimony that Equitable’s practice of negotiating
14 discounted rates for certain customers is improper practice given the LDC market
15 structure that currently exists in Western Pennsylvania, nor that Equitable should be
16 prohibited from recognizing these discounts, per se for ratemaking purposes. It is my
17 position and testimony that as a regulated public utility, Equitable has a responsibility and
18 obligation to justify, support, and document the prudence and necessity of these
19 discounts.

20 **Q. ON PAGE 32 OF HIS REBUTTAL TESTIMONY, MR. QUINN STATES: “I**
21 **THINK MR. WATKINS’ TESTIMONY IS EXTREMELY MISLEADING AND**
22 **CONTRARY TO THE FACTS.” PLEASE COMMENT ON THIS STATEMENT.**

23 A. I will not engage in a “he said/she said” discussion with Mr. Quinn on this
24 accusation. I presented an accurate and unbiased description of the facts and
25 circumstance surrounding Equitable’s failure to provide any meaningful data regarding
26 negotiated discounted rates during the discovery phase of this case. Suffice it to say that
27 I sought the data necessary to review whether the negotiated discounted rates were

1 justified and whether the Company had maximized revenue for the benefit of its other
2 ratepayers. With over 800 customers receiving such discounts, this is a cumbersome task
3 that places a burden on Equitable to justify this activity. Equitable did not see any need
4 to meet this burden until Rebuttal.

5 **Q. ON PAGE 28 OF HIS REBUTTAL TESTIMONY, MR. QUINN CLAIMS THAT**
6 **YOUR RECOMMENDED REVENUE ADJUSTMENT TO DISCOUNTED RATES**
7 **IS ARBITRARY, DISCRIMINATORY AND CONFISCATORY. PLEASE**
8 **COMMENT ON THESE ALLEGATIONS.**

9 A. First, I calculated the difference between the Company's specific claimed
10 negotiated rate revenues and those generated at Commission approved maximum rates
11 (i.e., those paid by captive customers). There is nothing arbitrary or discriminatory about
12 this calculation or determination. In this case, Equitable is seeking an approximate \$52.0
13 million increase in revenues from captive customers. Although Equitable's captive and
14 negotiated rate customers are regulated under the jurisdiction of this Commission, I
15 attempted to investigate the level, and reasonableness, of the revenues generated from
16 discounted rates, as well as the prudence and reasons for such discounts. As discussed
17 earlier, not only did Equitable not justify the revenues attributable to negotiated discount
18 rate customers on its own accord as required by statute, it did not provide the information
19 the OCA sought in its investigative efforts in this area. It is Equitable that is seeking a
20 substantial increase in captive customers' rates in this case. My proposed revenue
21 adjustment simply rejects the Company's request to have captive ratepayers shoulder the
22 burden of these discounted rates to favored customers due to the fact that adequate
23 justification and support was not provided by the Company.

1 **Q. ARE SOME OF EQUITABLE'S RATE DISCOUNTS OFFERED TO SELECTED**
2 **FAVORED CUSTOMERS LIKELY JUSTIFIABLE?**

3 A. Yes. So that the Commission and all parties are clear, there is absolutely no doubt
4 that much, if not most, of Equitable's LDC gas on gas discounted revenue is prudent and
5 justifiable given the current practice of this Commission to allow competition between
6 intra-state LDCs. Although the practice of LDC gas on gas competition is the ultimate
7 cause of the problem and controversy in this case, it does not excuse the need for
8 Equitable to justify its rates charged to captive ratepayers, or its need for an increase in
9 rates to these captive ratepayers.

10 I will reiterate my recommendation and need for this Commission to open a
11 generic investigation as to the costs and benefits to ratepayers, utility shareholders, and
12 the Commonwealth of Pennsylvania at large associated with the practice of LDC gas on
13 gas competition in Western Pennsylvania as this case clearly demonstrates the costliness
14 of this practice to captive ratepayers.

15 **Q. ON PAGE 28 OF HIS REBUTTAL TESTIMONY, MR. QUINN CLAIMS THAT**
16 **"THE COMPANY CAN VERIFY AND SUPPORT ITS NEGOTIATED RATE**
17 **REVENUE IN EVERY INSTANCE." PLEASE COMMENT ON THIS**
18 **STATEMENT.**

19 A. As part of his rebuttal testimony, Mr. Quinn provides a highly confidential
20 Exhibit that is comprised of a series of letters, e-mails, and correspondence regarding
21 negotiated rates. Although these documents do provide some support for its negotiated
22 rates, it is neither complete nor does it present a full analysis. In this regard, I
23 recommend that the Commission order Equitable to maintain organized, complete, and

1 detailed records regarding negotiated rates. These records should include on a customer
2 by customer basis, the specific reasons for a discounted rate including records and
3 support for each discount (e.g., LDC gas on gas competition, threat of interstate pipeline
4 bypass, alternative fuel threats, etc.). Equitable should also be required to conduct (or
5 have conducted) analyses and support for discounts offered due to the cost of alleged
6 alternative supplies or suppliers. These analyses should include a determination of the
7 maximum rate (lowest discount) that can be charged each customer and provide the
8 specific costs of alternatives. In the case of alternative fuels, this would include the cost
9 of alternative fuels plus an assessment of whether such fuels are a realistic possibility.
10 Finally, these analyses should be kept current and updated in a reasonable manner and
11 available, under appropriate proprietary Order, in a base rate case. This is particularly
12 true for discounts given to customers with claimed alternative fuel capabilities. A similar
13 requirement was ordered by the Commission for PPL Gas in Docket No. R-00061398.

14 **Q. WHAT DO YOU RECOMMEND AS TO THE NEGOTIATED RATE ISSUE?**

15 A. I recommend that the ALJ and the Commission review the materials to determine
16 if the Company has met their burden of proof for all or part of these discounts. On a
17 going forward basis, I recommend that the Commission require the Company to provide
18 information and analysis, as I have described above, in their direct case in subsequent
19 base rate filings.

20 **Q. PLEASE COMMENT ON THE REBUTTAL TESTIMONY OF IOGA WITNESS**
21 **DIANE BURGRAFF.**

22 A. Ms. Burgraff claims that I have improperly assigned costs and revenue
23 responsibility to Gathering Service (rate AGS) customers. As indicated in my rebuttal

1 testimony, my analyses and recommendations concerning rate AGS were predicated on
2 Equitable's direct assignment of gathering facility costs to that class, the distinctly
3 different services provided to natural gas producers for gathering of natural gas, and the
4 representations by Equitable regarding the use of these gathering facilities. I have
5 reviewed the rebuttal testimonies of Equitable witnesses Rafferty, Feingold, and Dalena
6 concerning the cost, use, and revenue associated with gathering services and conclude
7 that compelling evidence is presented in support of Equitable's direct assignment of costs
8 and proposed revenue responsibility for rate AGS customers. As such, I maintain my
9 original recommendations concerning AGS cost and revenue responsibility.

10 **Q. PLEASE COMMENT ON OSBA WITNESS KALCIC'S REBUTTAL**
11 **TESTIMONY.**

12 A. I will comment on two issues raised by Mr. Kalcic in his rebuttal testimony. The
13 first issue relates to the assignment or calculation of income taxes for class cost of service
14 purposes, and the second relates to Mr. Kalcic's understanding from his client (OSBA)
15 that the Commission's newly preferred natural gas cost allocation method is not the Peak
16 and Average method, but rather what is known as the Average and Excess method.

17 With respect to income taxes, Mr. Kalcic recommends that my recognition of
18 interest expense as a significant and substantial deduction from taxable income be
19 rejected because I do not also reflect every other minor adjustment considered in actual
20 tax determinations. I frankly do not understand Mr. Kalcic's rationale for this criticism.
21 Whereas, Mr. Kalcic readily admits that the Company's CCOSS is in error because it did
22 not reflect the deductibility of Operating and Maintenance expenses, and concurs that this
23 recognition is appropriate, he does not agree that the deduction of interest expense,

1 totaling \$17.0 million should also be considered. While Mr. Kalcic is correct that I did
2 not attempt to reconcile every single tax deduction, there is no denying the fact that
3 interest expense for a LDC is a major determinant of income tax expense. As such, while
4 my approach may not be surgically precise, it captures the vast majority of causative
5 factors influencing income tax cost responsibility, and is a significant improvement over
6 the approach used by Equitable.

7 **Q. ON PAGE 6 OF HIS REBUTTAL TESTIMONY, MR. KALCIC STATES THAT**
8 **COUNSEL INFORMED HIM THE “COMMISSION APPROVED THE**
9 **AVERAGE AND EXCESS (“A&E”) COST METHODOLOGY (AND NOT THE**
10 **OCA’S P&A METHODOLOGY) IN TWO (2) RECENT BASE RATE**
11 **PROCEEDINGS.” DID YOU SPONSOR A COST OF SERVICE STUDY IN**
12 **EITHER OF THE RATE PROCEEDINGS REFERRED TO BY MR. KALCIC?**

13 A. Yes. I conducted the CCOSS sponsored by the OCA in the PPL Gas case Mr.
14 Kalcic refers to. I did not participate in the Philadelphia Gas Works case which is the
15 other case referenced by Mr. Kalcic.

16 **Q. CAN YOU COMMENT ON THE COST OF SERVICE STUDIES IN THESE**
17 **CASES?**

18 A. Yes. First, as I will explain later, I did not conduct or sponsor a P&A based
19 CCOSS in the PPL Gas case, and none was offered by the OCA. As will be explained
20 later, this was not an endorsement of the Average and Excess method or a rejection of the
21 Peak and Average method. Secondly, and as I will discuss below, apparently Mr. Kalcic
22 is unaware of the detailed findings in the PGW case.

1 **Q. PLEASE CONTINUE.**

2 A. Before I discuss the specifics concerning the PPL Gas and PGW cases, it is
3 important to understand the differences between the Peak and Average and Average and
4 Excess methods, particularly as they relate to the end results obtained for most natural
5 gas LDC's. As correctly noted by Mr. Kalcic on page 8, lines 23 through 28 and footnote
6 7, of his rebuttal testimony, the Average and Excess method (when applied to natural gas
7 LDC's) generally produces equivalent results as those obtained under the design day
8 Peak Responsibility method.¹

9 In the PPL Gas case (in which I participated and sponsored a CCOSS study), the
10 Company sponsored a CCOSS study in which distribution Mains were allocated based on
11 the A&E method. During the course of this PPL Gas proceeding, OSBA's witness,
12 Robert Knecht objected to the allocation of Mains based on the A&E method and
13 proposed an allocation method in which the demand component of Mains was allocated
14 based entirely on peak demand. Mr. Knecht did not object to the A&E method on its
15 conceptual merits but rather on his claim that Company witness Paul Herbert developed
16 his A&E allocator based on non-diversified demands, which are the same as CP (spell
17 out?) demands. As such, Mr. Knecht's objection in the PPL Gas case was that the A&E
18 methods used by Mr. Herbert did not produce the same results as a Peak Responsibility
19 approach. In rebuttal Mr. Herbert stated that the demands he used were not CP but rather
20 NCP demands and that there was proper diversity in his class demands.² Neither the
21 Staff nor I proposed alternatives to Mr. Herbert's A&E allocator in that case, but instead

¹ A mathematical proof, or example, as to why this generally occurs is not provided because the mechanics are moot given Mr. Kalcic's acknowledgement that the Average and Excess Method generally produces virtually identical results as the Peak Responsibility Method for natural gas LDC's.

² PA PUC v. PPL Gas Utilities, R-00061398. Herbert Rebuttal Testimony at page 4.

1 focused on other CCOSS issues. The reason I did not propose an alternative to Mr.
2 Herbert's A&E allocator was because in that case, there was a distinct recognition of
3 average demands (throughput) and identical results were not obtained using the Peak
4 Responsibility method. The Commission's decision in the PPL Gas case rejected Mr.
5 Knecht's proposed peak demand allocator.³ As such, I cannot see the PPL Gas case as
6 "precedent" setting as far as endorsement of, or guidance regarding, a particular
7 allocation method to assign distribution Mains cost responsibility.

8 Although I did not participate in the PGW case referred by Mr. Kalcic, the
9 Administrative Law Judges' Recommended Decision and the Commission's Order in that
10 case also do not appear to be precedent setting as far as a specific distribution Mains
11 allocation method is concerned. In its Order, the Commission did however, make the
12 following finding.

13 "Reviewing the record, we find that the allocation of distribution Mains
14 investment costs should be done using both annual and peak demands."⁴
15

16 The Commission found that the allocation of Mains costs should consider both average
17 usage (annual) and peak demands. In this regard, the A&E method generally is almost
18 entirely weighted to peak demand with very little, if any, weight given to annual usage
19 (average daily usage).

20 Conversely, the Peak and Average allocators used in Equitable's Peak and
21 Average study and also used by me in my CCOSS gives equal weight to annual usage
22 and peak demand. The Commission did not state how much weight should be given to
23 annual usage and peak demands in the PGW case. In my opinion, a virtual 100% peak

³ PA PUC v. PPL Gas Utilities, R-00061398. Order at pages 113 and 114.

⁴ PA PUC v. Philadelphia Gas Works, R-00061931, Order at page 80.

1 demand weighting scheme does not fulfill the spirit of the Commission's guidance from
2 the PGW case.

3 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

4 A. Yes.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08

AB6, PA

RJS

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

DIRECT TESTIMONY OF

ROGER D. COLTON

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

October 8, 2008

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1 **Q. PLEASE STATE YOUR NAME AND ADDRESS.**

2 A. My name is Roger Colton. My address is Fisher, Sheehan & Colton, Public Finance and
3 General Economics, 34 Warwick Road, Belmont, Massachusetts 02478.

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

5 A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General
6 Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a
7 variety of federal and state agencies, consumer organizations and public utilities on rate and
8 customer service issues involving telephone, water/sewer, natural gas and electric utilities.

9 **Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?**

10 A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA") of
11 Harrisburg, Pennsylvania.

12 **Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.**

13 A. I work primarily on low-income utility issues. This involves regulatory work on rate and
14 customer service issues, as well as research into low-income usage, payment patterns, and
15 affordability programs. At present, I am working on various projects in the states of New
16 Hampshire, Maryland, Pennsylvania, North Carolina, Ohio, Indiana, Iowa, Colorado, New
17 Mexico, Oregon and Washington. My clients include state agencies (*e.g.*, Pennsylvania
18 Office of Consumer Advocate, Maryland Office of Peoples Counsel, North Carolina
19 Department of Justice, Iowa Department of Human Rights), federal agencies (*e.g.*, U.S.
20 Department of Health and Human Services), community-based organizations (*e.g.*,
21 Community Action of New Mexico, Coalition to Keep Indiana Warm, Community Action
22 Partnership of Oregon), and private utilities (*e.g.*, Entergy Services, Citizens Gas and Coke
23 Utilities, Northern Indiana Public Service Company, Tacoma Public Utilities). In addition

1 to state- and utility-specific work, I engage in national work in the United States and
2 Canada. For example, I am currently working on a national study of the responses of water
3 utilities to the payment troubles of residential customers for the American Water Works
4 Association Research Foundation. In 2007, I was part of a team that performed a multi-
5 sponsor public/private national study of low-income energy assistance programs.

6 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

7 A. After receiving my undergraduate degree in 1975, I obtained further training in both law and
8 economics. I received my law degree in 1981; I received my Masters Degree (economics)
9 in 1993. A copy of my curriculum vitae is appended as Attachment RC-1.

10 **Q. HAVE YOU AUTHORED ARTICLES ON PUBLIC UTILITY REGULATORY**
11 **ISSUES?**

12
13 A. Yes. I have published more than 80 articles in scholarly and trade journals, primarily on
14 low-income utility and housing issues. I have published an equal number of technical
15 reports for various clients on energy, water, telecommunications and other associated low-
16 income utility issues. My publications are listed in Attachment RC-1.

17 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY**
18 **COMMISSIONS?**

19
20 A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PUC" or
21 "Commission") on a variety of low-income energy, water and telecommunication issues
22 over the past 20 years. In addition, I have testified in regulatory proceedings in more than
23 30 states and various Canadian provinces on a wide range of low-income water,
24 telecommunications and energy issues. Proceedings in which I have previously appeared as
25 an expert witness are listed in Attachment RC-1.

1 **Q. PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY.**

2 A. The purpose of my testimony is two-fold. First, I will review the reasonableness of the
3 universal service costs that Equitable Gas proposes to collect through its Rider D.
4 Second, I will assess the extent to which Equitable Gas has complied with the directives
5 of the Pennsylvania Public Utility Commission ("PUC") to calculate the cost-offsets to be
6 used in funding the Company's universal service programs.

7 **Part 1. The Company's Proposed Rider D Universal Service Cost Recovery.**

8 **Q. PLEASE EXPLAIN THE COSTS THAT EQUITABLE GAS PROPOSES TO**
9 **RECOVER THROUGH ITS "RIDER D."**

10
11 A. The Company proposes to recover the costs of its Customer Assistance Program ("CAP")
12 and LIURP programs through its Rider D. The Company proposes that Rider D be
13 implemented as a reconcilable surcharge imposed on residential non-CAP customers. On
14 an annual basis, the Company estimates what it expects to spend on its Universal Service
15 costs using both known and projected information. The Company then provides a
16 quarterly reconciliation of its actual expenditures to its expected expenditures. The
17 Company either returns over-expenditures to customers (with interest) or collects its
18 under-expenditures (also with interest). The objective, according to Company witness
19 Quinn, is to use the "best information available to minimize any over- or under-recovery
20 of actual universal service expenses." (Quinn Direct, at 30 – 31). The proposed Rider D
21 is similar to the current cost recovery mechanism for universal service costs with the
22 exception that Equitable does not currently reconcile the costs collected through its Rider
23 to its actual expenditures.

1 Q. GIVEN THE RECONCILIATION PROCESS, PLEASE EXPLAIN WHY IT IS
2 IMPORTANT TO MAKE THE CORRECTIONS TO THE CAP COST
3 RECOVERY YOU RECOMMEND BELOW.
4

5 A. In the case of Equitable's CAP administrative costs, I propose to take those costs out of
6 the reconcilable rate rider process. For the reasons I explain below, the CAP
7 administrative costs are most appropriately collected through base rates. Moreover, the
8 modifications I recommend below are based upon methodological flaws in estimating
9 CAP costs. While the reconciliation process for the prior period would return to
10 ratepayers the over-collection from that prior period, the methodological flaws would
11 result in the Company making the same over-estimation for the ensuing period. As a
12 result, ratepayers would effectively have a permanent loss of money. Finally, the
13 Company does not propose to recognize the cost offsets at all in the reconciliation
14 process. In each of these cases, the existence of the reconciliation process does not
15 adequately address the over-recovery of CAP costs.

16 Consider, for example, my recommended modifications concerning both the
17 overstatement of the number of bills issued to CAP customers and the overstatement of
18 CAP credits that are paid to CAP customers. While the reconciliation process for a prior
19 period may well reflect the over-recovery from that *prior* period, the estimates for the
20 *next* period would then be made based on the same methodology and would again result
21 in the same over-collection for the reasons I identify. As a result, even though each
22 period involves a reconciliation, the Company would permanently be in an over-
23 collection situation.
24

1 **Q. IS THERE A REASON WHY A PERMANENT OVER-COLLECTION**
2 **SITUATION IS NOT SOUND IF CUSTOMERS WILL BE MADE WHOLE FOR**
3 **PRIOR PERIOD OVER-COLLECTIONS?**
4

5 A. Yes. The permanent over-collection means that customers will never be completely
6 made whole. When an over-collection from the prior period is returned to customers, the
7 over-collection for the subsequent period is imposed. As a result, the Company will
8 permanently retain dollars that belong to the customers.

9 **Q. DOES THE COMPANY PROPOSE A SPECIFIC LEVEL OF ESTIMATED**
10 **UNIVERSAL SERVICE COSTS TO BE RECOVERED THROUGH ITS RIDER**
11 **D?**
12

13 A. Yes. In Attachment JMQ-2 to Company witness Quinn's testimony, the Company
14 identifies that it has total current funding for CAP and LIURP of \$11,401,984
15 (Attachment JMQ-2, Line 32). It projects total CAP/LIURP dollars to be recovered equal
16 to \$28,276,683. (Attachment JMQ-2, Line 27). Accordingly, the Company seeks an
17 *additional* \$16,874,700 in CAP/LIURP funding in this proceeding beyond that which is
18 already being collected in rates ($\$28,276,683 - \$11,401,984 = \$16,874,700$).

19 The proposed Rider D is designed to recover the entire \$28,276,683, not merely
20 the \$16,874,700 identified as new universal service funding needs in this proceeding. In
21 other words, Rider D is designed to collect \$28,276,683, which results in a charge of
22 \$1.4384 per MCF for residential, non-CAP customers (Attachment JMQ-2, Line 36).

23 **Q. DOES THE COMPANY CALCULATE THE COSTS TO BE RECOVERED**
24 **THROUGH ITS RIDER D IN AN APPROPRIATE FASHION?**
25

26 A. No. The Company overstates the costs that it should be allowed to recover through its
27 Rider D. Moreover, the Company fails to account for the expense offsets that provide for
28 universal service cost recovery outside of rates charged to customers. In this section of

1 my testimony, I will assess the extent to which Equitable overstates its universal service
2 costs.

3 **A. Number of CAP Bills.**

4 **Q. PLEASE EXPLAIN THE FIRST PROBLEM THAT YOU IDENTIFY IN THE**
5 **COMPANY'S ESTIMATION OF CAP COSTS TO BE RECOVERED THROUGH**
6 **RIDER D.**

7
8 A. The Company's estimate of CAP costs to be recovered through Rider D overstates the
9 number of monthly bills that the Company can be expected to issue to CAP customers
10 during the billing period.

11 **1. The Company Cost-Estimation Procedure.**

12 **Q. HOW DOES AN OVERSTATEMENT OF THE NUMBER OF CAP BILLS**
13 **AFFECT THE TOTAL CAP COSTS THAT THE COMPANY PROPOSES TO**
14 **RECOVER THROUGH RIDER D?**

15
16 A. The total CAP costs that the Company proposes to recover through Rider D is based on
17 the difference between what CAP participants pay under the Company's CAP program
18 and the revenue that would have been billed to those customers at standard residential
19 rates in the absence of the program. In other words, if the billed revenue at standard
20 residential rates is \$100, and the CAP payment is \$75, the "CAP shortfall" (or "CAP
21 credit") is \$25. It is that \$25 CAP credit that is then passed through Rider D to all other
22 residential ratepayers. Accordingly, should the Company overstate the revenue that
23 would have been billed at standard residential rates in the absence of the program, the
24 CAP shortfall will be overstated as well.

25 In the Company's estimating process, the estimated amount of revenue that would
26 have been billed in the absence of CAP is based upon the Company's projection of the

1 number of monthly bills it will render to CAP participants. As set forth in Company
2 Attachment JMQ-2, the Company engages in a two-step process:

3 ➤ First, the Company multiplies the number of bills by the monthly fixed
4 customer charge to obtain the amount of customer charge revenue that it
5 would have billed in the absence of CAP.

6 ➤ Second, the Company multiplies the number of bills by the average
7 consumption per bill to obtain the total consumption for its CAP population. It
8 then multiplies that total consumption by the various components of the
9 commodity price to obtain the amount of commodity revenue that it would
10 have billed in the absence of CAP.

11 Accordingly, if the Company overstates the number of bills that it expects to render to
12 CAP customers, it will overstate the revenue it would have expected to bill in the absence
13 of CAP. If the Company overstates the revenue it would have expected to bill in the
14 absence of CAP, it will, in turn, overstate the CAP shortfall that should be collected
15 through the Company's proposed Rider D.

16 In my testimony below, I explain the overstatement of the number of CAP bills,
17 along with the impact that overstatement has on the revenue the Company would have
18 expected to bill at standard rates in the absence of the CAP program.

19 **2. The Overstatement of the Number of Monthly CAP Bills.**

20 **Q. HOW DOES THE COMPANY OVERSTATE THE NUMBER OF BILLS IT**
21 **EXPECTS TO RENDER TO CAP CUSTOMERS?**

22
23 A. The Company estimates that it will render 227,712 bills to CAP participants. (Attachment
24 JMQ-2). It calculates that figure by assuming that the Company will have 18,976 CAP
25 participants. By multiplying that participation rate by 12 months, it derives its 227,712

1 figure (18,976 cap participants x 12 months = 227,712 monthly bills to CAP
2 participants).

3 **Q. IS THE COMPANY CORRECT IN USING A PARTICIPATION RATE OF 18,976**
4 **FOR PURPOSES OF ESTIMATING THE NUMBER OF BILLS IT WILL ISSUE**
5 **TO ITS CAP PARTICIPANTS?**

6
7 A. No. In using the 18,976 figure, the Company erroneously assumes that the CAP
8 participation rate will equal 18,976 throughout the year. That assumption is in error. The
9 Company will not average 18,976 full-time equivalent CAP participants in each month.

10 **Q. UPON WHAT DO YOU BASE THAT CONCLUSION?**

11 A. In response to OCA discovery requests, the Company provided a database with
12 comprehensive CAP data in it for all CAP participants for the months of January 2007
13 through July 2008. That database provides the monthly data of individual CAP
14 participants for, among other items, the total participants, current bills, total amount due
15 by month, total CAP credit granted, total arrearage forgiveness granted, and
16 consumption.

17 Based on my analysis of that data, I conclude that there will not be 18,976 full-
18 time equivalent CAP participants for the Company per month. I do not dispute the
19 Company's estimate of 18,976 as a *year-end* 2008 figure for total CAP participants
20 (Attachment JMQ-2). The Company indicates that it calculated the 18,976 number of
21 CAP participants by escalating the March 2008 number of participants by its 2007
22 growth patterns. (OTS-RE-122-D). I derived basically the same 19,000 participation
23 figure by escalating the January 2008 number of participants reported in the CAP
24 database provided in response to OCA discovery questions (OCA-V-12) (n=16,210) by
25 the rate of participation increase in 2007 (14%) reported in that same database.

1 To use a year-end number (i.e., a single point in time), however, to estimate the
2 total year-round full-time equivalent participants will overstate the total number of bills
3 rendered to CAP participants over the course of the year. By way of example, since the
4 year-end participation rate for 2007 was 16,210 CAP participants, using the Company's
5 methodology would have estimated a total of 194,520 monthly bills to CAP participants
6 for 2007. The *actual* number of bills rendered to CAP participants in 2007, however, was
7 only 182,510, a difference of nearly seven percent (7%).

8 **Q. WHAT DO YOU RECOMMEND WITH REGARD TO THE CALCULATION OF**
9 **THE PROJECTED NUMBER OF CAP BILLS THE COMPANY WILL**
10 **RENDER?**

11
12 A. I recommend that, rather than applying its escalation rate to derive a year-end number,
13 the Company apply its 14% growth rate to the 2007 average number of CAP participants
14 receiving bills (15,209) to estimate the number of full-time equivalent participants per
15 month for 2008. The projected number of estimated full-time equivalent participants
16 would thus be 17,338 ($15,209 \times 1.14 = 17,338$). Annualizing that figure to account for 12
17 monthly bills yields a total of 208,059 annual bills rather than the Company's estimated
18 227,712. It is this 208,059 figure that I use in my CAP cost calculations.

19 **Q. SHOULD THE COMPANY USE THIS METHODOLOGY IN ESTIMATING**
20 **FUTURE CAP COSTS FOR COLLECTION THROUGH RIDER D?**

21
22 A. Yes. In estimating CAP costs on a going-forward basis for purposes of calculating the
23 Rider D surcharge, I recommend that the Company begin with the number of average
24 full-time equivalent CAP participants, using the prior year as the base year (e.g., 2007
25 base for 2008 estimate; 2008 base for 2009 estimate). I recommend that that number of
26 full-time equivalent CAP participants per month then be escalated by the growth rate in
27 CAP participants during that base year. This determination of the estimated number of

1 CAP participants will affect the overall calculation of customer charge revenue,
2 commodity revenue, and CAP payments.

3 **Q. IS THERE A SECOND ADJUSTMENT YOU RECOMMEND BE MADE TO THE**
4 **NUMBER OF BILLS TO BE USED IN CALCULATING CAP COSTS?**

5
6 A. Yes. In discussing the Equitable Gas CAP program, there is a difference in the use of
7 terminology that should be accounted for in the calculation of the Company's cost
8 recovery through the proposed Rider D. The Company reports that it had 18,805 CAP
9 "participants" in July 2008.¹ Merely because a customer is listed as a "CAP participant,"
10 however, does not mean that the customer received a CAP bill in that month. Only if a
11 participant receives a CAP bill with usage charges does the customer receive a CAP
12 credit. Only if a participant receives a CAP credit does the Company incur a CAP
13 expense that is subject to recovery through Rider D.

14 According to the Company's database provided to OCA (OCA-V-12), during
15 2007, only 98.5% of customers listed as a "CAP participant" received a CAP bill that had
16 usage associated with it. While the 1.5% difference may, at first glance, appear
17 insubstantial, it yields a total number of bills rendered to CAP participants of 204,885
18 rather than the 208,059 calculated using the total number of full-time equivalent CAP
19 participants discussed above. The financial impact is significant.

20 **Q. DOES YOUR PROPOSED NUMBER OF BILLS RECOGNIZE THE FACT THAT**
21 **THE COMPANY ALREADY REPORTS A JULY 2008 PARTICIPANT**
22 **POPULATION OF 18,805?**

23
24 A. Yes. While the database provided to OCA reveals only 18,602 CAP participants in July
25 2008, I understand that the Company reported a July 2008 participation rate of 18,805 in

¹ The database that the Company provided to OCA included only 18,602 participants in July 2008 (OCA-V-12).

1 response to discovery questions from the Office of Trial Staff ("OTS"). (OTS-RE-122-

2 D). I do not find either July 2008 number to be dispositive. Four reasons exist for this.

3 ➤ First, it is not the participation rate at any single point in time that is important
4 in calculating CAP expenses to be passed through Rider D. It is the
5 participation rate over the full year that is important. The full-time equivalent
6 participation rate is calculated by summing the total number of CAP monthly
7 bills and dividing that figure by 12. If I have 10 CAP participants for the first
8 six months of a year, and 20 CAP participants for the second six months, I do
9 not have annual expenses associated with 20 participants. I instead have
10 expenses associated with 15 full-time equivalent participants $[(10*6) +$
11 $(20*6)] / 12 = 15$).

12
13 ➤ Second, merely because the CAP participation rate in July was 18,805 does
14 not mean that the participation rate will increase. According to the CAP
15 database provided by the Company to OCA (OCA-V-12), in 2007, for
16 example, the CAP participation rate did not consistently increase from month-
17 to-month. The Company had 15,532 participants in June 2007 and 15,524 in
18 July 2007. By September 2007, the number of participants had decreased to
19 15,143; the number of participants had further decreased to only 15,088 by
20 October 2007. Taking the July participation as a starting point, and escalating
21 the number of participants from that starting point, does not yield accurate
22 results.

23
24 ➤ Third, the adjustment for the number of CAP participants who do not receive
25 CAP bills would apply to the Company's reported July 2008 participation
26 figure as well. The Company's database provided to OCA reveals that 1.4%
27 of July customers reported as being "CAP participants" did not receive CAP
28 bills (or received CAP bills with no usage).

29
30 ➤ Finally, while a July participation rate of 18,805 may increase the total
31 number of full-time equivalent participants when combined with previous
32 months, it would not make the full-time equivalent number equal to that July
33 participation figure. For example, the database of CAP participant data
34 provided to OCA reports that the January 2008 number of CAP participants
35 receiving bills was only 16,202. (OCA-V-12). The 18,805 participation rate
36 must be blended with all other monthly participation rates to achieve a correct
37 annual cost estimate.

38
39 The estimates I set forth above are not inconsistent at all with the Company's reported
40 July 2008 participant population of 18,805.

1 **3. The Overstatement of Billings at Standard Residential Rates in the Absence of CAP.**

2 **Q. HOW DOES THE OVERSTATEMENT OF THE NUMBER OF BILLS TO CAP**
3 **PARTICIPANTS AFFECT THE CAP COST RECOVERY THROUGH RIDER D?**

4
5 A. As I explain in more detail above, Rider D is designed to compensate the Company for
6 the CAP credits (CAP shortfall) that the Company provides to CAP participants. The
7 CAP shortfall is the difference between what the Company would have billed at standard
8 residential rates and what the Company does, in fact, bill at CAP rates. To the extent that
9 the number of bills to CAP participants is overstated, the Company overstates the revenue
10 it would have billed at standard residential rates and would, therefore, also overstate the
11 CAP shortfall to be collected through Rider D. The overstatement of the number of bills
12 first affects the amount of revenue that the Company estimates it would have billed
13 through its fixed monthly customer charge. The overstatement of the number of bills also
14 affects the amount of commodity charge revenue the Company estimates it would have
15 billed in the absence of CAP.

16 **Q. WHAT IMPACT DOES THE OVERSTATEMENT OF THE NUMBER OF BILLS**
17 **RENDERED TO CAP PARTICIPANTS HAVE ON THE COMPANY'S**
18 **ESTIMATE OF WHAT REVENUE WOULD HAVE BEEN BILLED THROUGH**
19 **THE FIXED MONTHLY CUSTOMER CHARGE IN THE ABSENCE OF CAP?**

20
21 A. The Company's cost recovery estimates are based on an assumption that it will render
22 227,712 monthly bills to CAP participants (Attachment JMQ-2). Applying a fixed
23 customer charge of \$11.65 associated with each bill yields the Company's estimate of
24 \$2,652,845 in revenue that would have been billed to CAP participants at standard
25 residential rates (Attachment JMQ-2).

1 My two adjustments to the number of monthly bills to CAP participants are: (1) using the
2 number of full-time equivalent CAP participants for 2008 (208,059); and (2) adjusting for
3 those full-time equivalent CAP participants that do not receive a bill in a particular month
4 (1.5%). Applying these two adjustments yields a total number of bills of 204,885.
5 Applying the fixed monthly customer charge of \$11.65 to each bill yields an estimated
6 revenue of \$2,386,916 from fixed monthly customer charges at standard residential rates.
7 This is a reduction of \$265,929 in customer charge revenue from the Company's estimate
8 in Attachment JMQ-2.

9 **Q. DOES THE DIFFERENCE IN THE NUMBER OF BILLS RENDERED AFFECT**
10 **THE TOTAL CONSUMPTION UNDERLYING THE COMPANY'S CAP COST**
11 **ESTIMATE?**
12

13 A. Yes. The Company projects an annualized and normalized volume of gas consumption of
14 2,528,091 MCF for its CAP customers (Attachment JMQ-2). The Company derives this
15 consumption figure as follows:

- 16 ➤ The Company begins with its estimated participation rate of 18,976 CAP
17 participants (Attachment JMQ-2);
- 18 ➤ The Company projects an average annual consumption of 11.1 MCF per
19 billing month (Attachment JMQ-2);
- 20 ➤ The Company uses 12 bills per year for CAP participants.
- 21 ➤ Multiplying these factors yields the gas consumption of 2,528,091 MCF
22 $(18,976 \text{ participants} \times 12 \text{ months per year} = 227,712 \text{ monthly bills per year} \times$
23 $11.1 \text{ MCF monthly consumption per participant} = 2,528,091 \text{ MCF total}$
24 $\text{annual CAP consumption}).$

1 I agree with that estimate. The database provided to OCA (OCA-V-12) yields an average
2 usage per billing month of 11.1 MCF for 2007 (some minor variation may occur due to
3 rounding).

4 As I describe in detail above, my disagreement lies with the number of bills that
5 the Company estimates as rendering for its CAP population. Rather than rendering
6 227,712 bills to CAP participants, the Company will instead render only 204,885 bills.
7 Accordingly, rather than having an annual consumption of 2,528,091 MCF, the Company
8 will have CAP consumption of only 2,274,224 MCF (204,885 monthly bills per year x
9 11.1 MCF monthly consumption per participant = 2,274,224 MCF total annual CAP
10 consumption).

11 **Q. WHAT IMPACT DOES THIS OVERSTATEMENT OF TOTAL CAP**
12 **CONSUMPTION HAVE ON THE COMPANY'S ESTIMATE OF WHAT REVENUE**
13 **WOULD HAVE BEEN BILLED THROUGH THE VARIOUS COMPONENTS OF THE**
14 **COMMODITY CHARGE IN THE ABSENCE OF CAP?**
15

16 A. The Company included four different components in the commodity charge it uses to
17 calculate total revenue that would have been billed to CAP participants at standard
18 residential rates in the absence of CAP: the delivery charge, the Rider C-Transition Cost,
19 the Natural Gas supply charge, and the balancing charge (Attachment JMQ-2). This
20 commodity charge is applied to the total consumption of CAP participants to derive the
21 revenue that would have been generated at standard residential rates in the absence of
22 CAP. The commodity charge, when added to the fixed monthly customer charge,
23 comprise the customer's total natural gas bill to Equitable at standard residential rates.

24 I identify in my discussion above why the Company has overstated its CAP
25 consumption, and how a reduced consumption level necessarily flows from the lower
26 number of bills that the Company will issue to CAP customers. Since the total

commodity charge is calculated by multiplying consumption times the rate, the use of a lower consumption yields a total commodity charge of \$38,434,377 that would have been billed to CAP customers at standard residential rates in the absence of the CAP. I have set forth the calculation of the commodity charge in Schedule RDC-1, which is attached to my testimony below. This figure stands in contrast to the Company's projected \$42,724,062 (Attachment JMQ-2) from commodity charges.

Q. CAN YOU SUMMARIZE THE ADJUSTMENTS YOU MAKE?

A. Yes. The CAP credit (CAP shortfall) is the difference between what would have been billed to CAP participants at standard residential rates and what is actually billed to CAP participants under the CAP program. To the extent that the Company over-estimates the revenue that would have been billed at standard residential rates, it will thus also over-estimate the CAP shortfall. The two differences I identify are:

- The Company estimates that it will bill \$2,652,845 in fixed monthly customer charges in the absence of CAP, while I estimate that the Company will bill \$2,386,916 in fixed monthly customer charges in the absence of CAP.
- The Company estimates that it will bill \$42,724,062 in commodity charges at standard residential rates in the absence of CAP (Attachment JMQ-2), while I estimate that the Company will bill \$38,434,377 in commodity revenue in the absence of CAP.

Combining these two bill components (fixed monthly customer charge + commodity charge), the Company estimates that it will bill \$45,336,068 in total billings (net of STAS) at standard residential rates in the absence of CAP, while I estimate that the Company will bill \$40,784,554 (net of STAS) at standard residential rates in the absence

1 of CAP. This reduction of \$4,551,514 in billed revenue at standard residential rates in
2 the absence of CAP results in a reduction to the CAP credits to be passed through the
3 Company's Rider D.

4 **B. CAP Credits.**

5 **Q. WHAT IS THE THIRD ERROR THE COMPANY MAKES IN ITS PROPOSED**
6 **RIDER D COST RECOVERY CALCULATION?**

7
8 A. The Company overstates the CAP shortfall that it seeks to claim through its Rider D. The
9 Company identifies a CAP shortfall of \$26,498,953 (Attachment JMQ-2) to be collected
10 through its proposed Rider D. It estimates this shortfall by estimating the total bill
11 rendered to CAP customers at standard residential rates and subtracting the estimated
12 CAP customer payments (including LIHEAP payments). The sum of the CAP shortfall
13 plus the customer payments equals the total bill rendered to CAP customers at standard
14 residential rates.

15 The calculation that underlies the Company's proposed Rider D cost recovery
16 assumes, however, that CAP customers will make 100% of their payments and will,
17 accordingly, receive 100% of their CAP credits. Under the Equitable Gas program, a
18 CAP participant does not receive his or her CAP credit unless and until that participant
19 makes full payment of the CAP payment requirement. Since fewer than 100% of CAP
20 payments are made by CAP participants, the Company grants less than 100% of the CAP
21 credits that are potentially available.

22 **Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT FEWER THAN**
23 **100% OF CAP BILLS ARE ACTUALLY PAID?**

24
25 A. In the database provided by the Company in response to OCA discovery (OCA-V-12),
26 two of the elements that were included were the CAP budget amount billed each month

1 to CAP participants and the amount of the CAP customer payment that was actually
2 made. A third element provided in that database was the total amount due in any given
3 month by a CAP participant. That total amount due would include the current month's
4 CAP budget amount plus any unpaid budget amount from a prior month. In the twelve
5 months ending December 2007, the Company issued 182,510 bills to CAP customers,
6 and received 129,023 payments toward those bills (70.7% collection rate). In the twelve
7 months ending July 2008, the Company issued 203,989 bills to CAP participants and
8 received 142,651 payments toward those bills (69.9% collection rate). Clearly, the
9 Company's calculation based upon a 100% payment success rate overstates the CAP
10 credits that the Company will grant.

11 **Q. HAVE YOU ESTIMATED THE EXTENT TO WHICH THE COMPANY'S**
12 **PAYMENT OF CAP CREDITS IS OVERSTATED?**
13

14 A. Yes. I estimated the total dollars in CAP credits that were potentially payable by
15 subtracting the total CAP budget amount billed to CAP participants from the total bill for
16 current usage for the same time period. I then compared the actual dollars in CAP credits
17 granted during the same twelve-month period. By summing the total bill for current
18 usage for CAP participants in the database provided to OCA (OCA-V-12), I found that
19 the total bill for current usage was \$26,473,447 for the twelve month period ending
20 December 2007. By summing the total dollars of CAP bills rendered to the same
21 population, I found that the total CAP bill was \$13,812,012. By subtracting the total
22 dollars of CAP bills from the total dollars of bills for current usage at standard residential
23 rates, I found a potential CAP credit of \$12,661,435 had 100% of CAP budget amounts
24 been paid ($\$26,473,447 - \$13,812,012 = \$12,661,435$).
25

1 However, when I summed the total dollars of CAP credits the Company actually
2 granted for those customers, I found that the Company actually granted only \$9,373,863
3 in CAP credits in the same time period, which was only 74% of the total potential CAP
4 credits. Similarly, using the CAP database provided to OCA (OCA-V-12), and using the
5 same methodology, I found that in the twelve months ending July 2008, the total bill for
6 current usage was \$32,904,739, yielding a potential CAP credit of \$17,249,865.
7 However, the Company granted \$12,493,059 in CAP credits, or 72.4% of the total
8 potential CAP credits. Over the 18-month period of January 2007 through July 2008, the
9 Company granted \$20,262,662 in actual CAP credits out of a potential \$27,411,182
10 (73.9%).

11 **Q. HOW DO YOU RECONCILE THE FACT THAT ONLY APPROXIMATELY**
12 **70% OF THE PAYMENTS WERE MADE BUT MORE THAN**
13 **APPROXIMATELY 70% OF THE POTENTIALLY AVAILABLE CREDITS**
14 **WERE GRANTED?**
15

16 **A.** Equitable Gas grants its CAP credits when the full payment of a CAP bill is made. A
17 customer is thus able to “cure” his or her missed CAP payment from a prior month. If a
18 customer makes his or her June/July payments in July, the customer would have made
19 one payment but earned two months of CAP credit. Therefore, there is no inconsistency
20 in these two numbers.

21 **Q. WHAT ADJUSTMENT DO YOU RECOMMEND BE MADE TO THE**
22 **COMPANY’S PROPOSED RIDER D BASED ON THE COMPANY’S**
23 **OVERSTATEMENT OF THE PAYMENT OF CAP CREDITS?**
24

25 **A.** Based on the 74% payment rate of CAP credits (rounded up from 73.9%), I have reduced
26 the CAP shortfall subject to recovery by 26%. Before making this adjustment, I calculate
27 a total level of CAP credits of \$23,836,467 assuming that 100% of CAP credits were
28 granted (\$40,821,923 in bills at standard residential rates - \$16,948,087 in CAP customer

1 payments = \$23,836,467 in total CAP shortfall [net of STAS]). The impact of my
2 adjustment yields a reduction in CAP credits actually granted of \$6,197,481 ($\$23,836,467$
3 $\times (1 - 0.74) = \$6,197,481$).

4 **Q. CAN YOU SUMMARIZE AND CONSOLIDATE THE TOTAL ADJUSTMENTS**
5 **TO THE COMPANY'S RIDER D COST CALCULATION BASED ON YOUR**
6 **DISCUSSION ABOVE?**

7
8 A. Yes. My consolidated cost recovery figure, before calculating offsets, is set forth in
9 Schedule RDC-2. The figure is calculated using the following inputs:

10 ➤ The total billed revenue is calculated as described above, yielding billed
11 revenue of \$40,821,923 (Schedule RDC-2, Line 3).

12 ➤ I estimate an actual individual per-customer payment (including LIHEAP
13 payments) of \$82.72 per bill. This calculation uses the Company's own per-
14 customer payment figure ($\$18,837,172$ total payments / $227,712$ monthly bills
15 $= \$82.72$ customer payment per bill). (Equitable Gas Attachment JMQ-2).

16 ➤ I estimate total customer payments of \$16,948,087 ($\$82.72/\text{bill} \times 204,885$
17 bills) (Schedule RDC-2, Line 4).

18 ➤ I estimate the total CAP shortfall (using the Company's incorrect assumption
19 of a 100% payment rate) of \$23,873,206 ($\$40,821,923 - \$16,948,087$)
20 (Schedule RDC-2, Line 5).

21 ➤ I estimate the total CAP shortfall actually granted (and thus subject to cost
22 recovery) at \$17,666,172 ($\$23,873,206 \times 0.74 = \$17,666,172$) (Schedule
23 RDC-2, Line 7).

24 ➤ I exclude administrative expenses (which are discussed later in my testimony).

➤ I accept the CAP arrearage forgiveness costs of \$780,397 (Schedule RDC-2, Line 8).

➤ I accept the LIURP costs of \$698,139 (Schedule RDC-2, Line 9).

Based on these calculations, I recommend total CAP/LIURP costs to be recovered of \$19,144,708 before offsets (Schedule RDC-2, Line 10). A side-by-side comparison of the Company's proposed universal service cost recovery, and my proposed universal service cost-recovery (without offsets) is set forth in Schedule RDC-3.

The offsets required, however, before a final Rider D amount to be charged residential customers are discussed below.

D. Removal of CAP Administrative Costs from the Rider D Surcharge.

Q. WHAT EXPENSES SHOULD THE COMPANY RECOVER THROUGH ITS UNIVERSAL SERVICE RIDER?

A. The Company should collect the incremental expenses that are directly attributable to its universal service program through its proposed Rider D. Expenses that are not specifically universal service expenses, as well as expenses that are not incremental in nature, should not be recovered through Rider D. An incremental expense is one that the Company would not have incurred but for the universal service program.

Q. DOES THE COMPANY PROPOSE TO USE RIDER D TO RECOVER EXPENSES THAT ARE NEITHER INCREMENTAL NOR INCURRED SPECIFICALLY AS A RESULT OF ITS UNIVERSAL SERVICE PROGRAM?

A. Yes. The Company proposes to collect \$299,184 in CAP administrative expenses through its Rider D (Attachment JMQ-2). Administrative costs include a portion of its customer call center costs allocated to CAP along with certain staff costs described below. The Company's administrative expenses should be excluded from recovery through Rider D because these expenses are not incremental universal service expenses.

1 **Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT THE EQUITABLE**
2 **GAS CAP ADMINISTRATIVE EXPENSES ARE NOT INCREMENTAL**
3 **EXPENSES ATTRIBUTABLE TO THE CAP PROGRAM?**
4

5 A. The Company has three basic universal service staff positions: the EAP Administrator,
6 the Manager of Universal Service and Community Outreach ("Manager"), and the
7 Universal Service Associate ("Associate"). The Company has previously acknowledged
8 that the Manager and Associate positions are not positions created exclusively for the
9 CAP, but rather are job positions shared between CAP and non-CAP responsibilities.
10 Equitable could not identify what salaries and benefits are recovered as a universal
11 service cost. The Company should recover these administrative expenses through its base
12 rates, not through Rider D.

13 **Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT THE EQUITABLE**
14 **GAS CAP ADMINISTRATIVE EXPENSES ATTRIBUTED TO CAP**
15 **ENROLLMENT ARE NOT APPROPRIATELY RECOVERED THROUGH**
16 **RIDER D AS A CAP ADMINISTRATIVE EXPENSE?**
17

18 A. Because CAP enrollment expenses are not incremental universal service expenses, they
19 should not be recovered through Rider D. The CAP enrollment process was transitioned
20 from community-based organizations to the Company call center in October 2006. The
21 entire call center was outsourced to a third party in August 2006. The treatment of CAP
22 calls are rolled in with other customer service calls at the call center. The overall call
23 center expenses do not vary based on CAP enrollment activity. As can be seen, these call
24 center expenses are not incremental expenses attributable to the Company's universal
25 service programs. These expenses would be incurred regardless of whether CAP existed
26 or not. Accordingly, the expenses associated with the call center are base rate expenses.
27 They would be inappropriate to recover through Rider D.
28

1 **Q. HOW SHOULD EQUITABLE RECOVER ITS CAP ADMINISTRATIVE**
2 **EXPENSES?**

3
4 A. Equitable proposes to recover \$299,194 in administrative expenses through its Rider D. I
5 propose that this total of \$299,194 be excluded from recovery through Rider D. They
6 should instead be recovered through base rates.

7 **Q. IN PROPOSING TO EXCLUDE THESE EXPENSES FROM THE**
8 **RECONCILABLE RIDER, DO YOU DENY THE COMPANY ITS ABILITY TO**
9 **HAVE THESE EXPENSES FULLY RECOVERED?**
10

11 A. No. Under utility ratemaking, expenses and revenues are constantly changing. The day
12 after a rate decision goes into effect, the utility will experience some expenses that
13 increase while other expenses decrease. So long as the utility is earning its allowed rate
14 of return, it is fully recovering all of the expenses that were recognized in its most recent
15 rate case. However, even if the utility is not earning its allowed rate of return, the
16 shortfall cannot be ascribed to any particular expense. There is no reason to conclude
17 that universal service expenses are the last expenses to be paid (and thus not fully
18 recovered) rather than the first expenses to be paid. To remove these staffing and call
19 center expenses from the Rider D does not mean, at all, that these expenses are not
20 subject to full recovery. They are instead simply recovered through base rates.

21 **Part 2. Universal Service Cost Offsets.**

22 **Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR**
23 **TESTIMONY.**
24

25 A. In this section of my testimony, I outline the universal service cost offsets that are
26 necessary to fully implement the PUC's cost recovery principles. The PUC has
27 established principles that call for a utility to include in any proposed universal service

1 cost recovery, as an offset to cost recovery, cost savings it incurred in cash working
2 capital, bad debt expense, and credit and collection costs.

3 **A. Bad Debt Offset Associated with Incremental CAP Costs.**

4 **Q. PLEASE EXPLAIN THE BAD DEBT OFFSET YOU PROPOSE TO THE**
5 **COMPANY'S CAP RATE COST RECOVERY.**

6
7 A. The bad debt offset is designed to prevent the utility from collecting costs that it will no
8 longer incur as it expands its universal service programs. Confirmed low-income
9 customers that are in arrears and not participating in the Company's CAP program will
10 impose a bad debt expense on the Company. The bad debt expense created by the arrears
11 of these confirmed low-income customers is reflected in the Company's base rates paid
12 by all residential customers. As the Company expands its CAP program, the revenues
13 represented by the CAP shortfall will no longer be billed to those confirmed low-income
14 customers. Since that revenue is no longer billed to these confirmed low-income
15 customers, but recovered through base rates to all customers, the bad debt expense
16 associated with those billings will no longer be incurred. As a result, the incremental
17 CAP shortfall should be reduced by an offset equal to the incremental revenues collected
18 through the CAP program multiplied by the bad debt rate for confirmed low-income
19 customers.

20 **Q. WHAT IS THE VALUE OF THE BAD DEBT OFFSET TO THE EQUITABLE**
21 **GAS CAP COST RECOVERY?**

22
23 A. The bad debt offset is equal to the incremental cost recovery sought by the Company
24 times the most recent bad debt rate for confirmed low-income customers. The most
25 recent bad debt rate reported by the PUC's Bureau of Consumer Services ("BCS") for the
26 confirmed low-income customers of Equitable Gas was 15.83%. The incremental cost

1 recovery I calculate above is \$7,715,537 (\$19,117,521 total universal service costs -
2 \$11,401,984 universal service costs in current rates = \$7,715,537). Multiplied by 15.83%
3 yields a bad debt offset of \$1,221,370 ($\$7,715,537 \times 0.1583 = \$1,221,370$).

4 **Q. DOES THIS BAD DEBT OFFSET INCLUDE THE COMPANY'S ARREARAGE**
5 **FORGIVENESS COST RECOVERY?**

6
7 A. Yes. Under the Company's arrearage forgiveness proposal, rather than continuing to bill
8 CAP participants for their preprogram arrears, the Company will forbear such billing and
9 instead grant arrearage forgiveness credits so long as the CAP participant makes the
10 required CAP payments. Accordingly, to the extent that the Company's proposed cost
11 recovery of \$780,397 for the forgiveness of pre-program arrears contributes to the
12 incremental cost recovery of \$7,715,537, it should also be reduced by the bad debt rate
13 for confirmed low-income customers.

14 **B. Working Capital Offsets Associated with Incremental CAP Costs.**

15 **Q. PLEASE EXPLAIN THE WORKING CAPITAL OFFSET YOU PROPOSE TO**
16 **THE COMPANY'S CAP RATE COST RECOVERY.**

17
18 A. In this section of my testimony, I identify the working capital reductions associated with
19 the reduction in arrears leading to bad debt write-offs in the set-offs accompanying the
20 Company's CAP cost recovery.

21 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

22 A. I outline above how and why the Company should reduce its cost recovery for its CAP
23 credits and arrearage forgiveness by 15.83% to reflect the reduced uncollectibles
24 generated by the CAP program. The PUC has indicated in both its existing and proposed
25 CAP regulations that a utility should reflect reductions in working capital in any CAP
26 cost recovery.

1 **Q. WHY WOULD THERE BE A REDUCTION IN WORKING CAPITAL?**

2 A. As I explain above, the reduction in uncollectibles occurs not because the Company
3 improves its collection rate, but rather because Equitable Gas would cease to bill these
4 amounts. With CAP credits, the Company ceases to bill the CAP participant a portion of
5 bills rendered for current usage and instead collects that amount from other customers.
6 With arrearage forgiveness, the Company ceases to bill the CAP participant for pre-
7 existing arrears and instead collects that amount from other customers.

8 **Q. AT WHAT POINT IN TIME DOES EQUITABLE WRITE-OFF AN**
9 **ARREARAGE AS UNCOLLECTIBLE?**

10
11 A. Equitable Gas deems a residential account to be uncollectible if the account remains
12 unpaid after the service is either discontinued at the customer's request or terminated and
13 two final bills are issued and are not paid.

14 **Q. HOW DO YOU CALCULATE AN AVOIDED WORKING CAPITAL EXPENSE?**

15 A. To calculate an avoided working capital expense, I use a two-step process. In Step 1, I
16 determine the expected age of the arrears prior to write-off. To do so, I determine the age
17 of a typical arrears for a confirmed low-income customer. Using the average arrears of
18 confirmed low-income customers, I find that these arrears represent five months of a
19 typical CAP Rate non-discounted bill. According to the most recent BCS universal
20 service report, the average arrears for a confirmed low-income customer for Equitable
21 Gas is \$402. Divided by a typical non-discounted monthly average bill of \$86, the
22 average age of arrears is five months ($\$402 / \$86 = 4.7$). In addition to this five month
23 age of the average arrears, I add the two month lag between the time an active account is
24 disconnected and the account is deemed to be uncollectible. The total lag, therefore, is

1 seven months (five months in arrears for an active account plus two months after a
2 disconnection occurs and a final bill is issued).

3 In Step 2, I apply a daily cost of capital to the lag I identify in the first step. In
4 calculating a multiplier in this fashion, there should be an additional 3.88% included to
5 account for the working capital associated with the Company's foregone write-off. The
6 calculation of this 3.88% is set forth in Schedule RDC-4. This offset should then be
7 applied to the marginal revenue identified in the Company's Rider D. The level of the
8 multiplier does not depend on the number of dollars to which the multiplier is applied.

9 **Q. WHAT IS THE VALUE OF THIS WORKING CAPITAL ADJUSTMENT?**

10 A. The working capital offset is equal to the incremental cost recovery sought by the
11 Company times the 3.88% offset rate calculated above. The incremental cost recovery
12 sought by the Company is \$7,715,537 (\$19,117,521 total universal service costs -
13 \$11,401,984 universal service costs in current rates = \$7,715,537). Multiplied by the
14 working capital adjustment that I calculate above (3.88%) results in a working capital
15 offset of \$299,363.

16 **Q. DOES THIS WORKING CAPITAL OFFSET ALSO APPLY TO THE**
17 **COMPANY'S ARREARAGE FORGIVENESS COST RECOVERY?**
18

19 A. Yes. Under the Company's arrearage forgiveness proposal, rather than continuing to bill
20 CAP participants for their preprogram arrears, the Company will forbear such billing and
21 grant arrearage forgiveness credits so long as the CAP participant makes the required
22 CAP payments. Accordingly, to the extent that the Company's proposed arrearage
23 forgiveness cost recovery contributes to the total increase in universal service costs, that
24 arrearage forgiveness should also be reduced by the working capital offset calculated
25 above.

1 **Q. IS THE APPLICATION OF A WORKING CAPITAL AND BAD DEBT**
2 **ADJUSTMENT TO ARREARAGE FORGIVENESS COST RECOVERY**
3 **CONSISTENT WITH PUC POLICY?**
4

5 A. Yes. In PUC's October 2006 final order with respect to the Commission's investigation
6 into CAP cost recovery, the PUC found:

7 Regarding arrearage forgiveness costs, it is not possible to make a definitive
8 ruling as to the entire amount of these costs. There is some merit in
9 reasoning that arrearage forgiveness amounts should not be recovered
10 separately because these are amounts that, but for the existence of the CAP
11 program, would be included within the utility's claim for uncollectible
12 expenses. The law requires "full recovery" of CAP costs, but not "double
13 recovery." At the same time, utilities should have the opportunity to
14 demonstrate when they seek to establish a surcharge that arrearage
15 forgiveness costs are not completely covered by uncollectible expenses. The
16 utilities should bear the burden of proving that allowing recovery of their
17 claim for arrearage forgiveness costs will not give them double-recovery of
18 these costs.
19

20 Final Investigatory Order, Customer Assistance Programs: Funding Levels and Cost
21 Recovery Mechanisms, Docket No. M-00051923, at 38 (October 19, 2006). Several
22 critical observations flow from this Commission order. First, the Commission
23 acknowledges that, at least for some portion of forgiven arrears, "these are amounts that,
24 but for the existence of the CAP program, would be included within the utility's claim for
25 uncollectible expenses." Second, while a utility is entitled to "full recovery," it is not
26 entitled to "double recovery." Finally, it is the Company that bears the burden of proving
27 that its cost recovery "will not give them double-recovery" of costs. While Equitable has
28 chosen to ignore this Commission directive, my proposal above is in full compliance with
29 this directive and gives the directive substance.

30 The Commission carries this policy forward into its currently pending proposed
31 CAP regulations (Universal Service and Energy Conservation Reporting Requirements
32 and Customer Assistance Programs, Docket No. L-00070186/57-257, 38 Pa. Bulletin 776

(February 9, 2008)). In its proposed regulations, the PUC provides that recoverable CAP Costs include “preprogram arrearage forgiveness to the extent that a distribution company can prove that recovery of these costs will not result in double recovery” (Proposed Rule §76.4(2)(iii)). Equitable, however, has made no such demonstration. Moreover, the Commission provides in its proposed regulations that “the company [seeking cost recovery] shall include, as an offset to cost recovery, cost savings it incurred in the following areas: (i) Cash working capital; [and] (ii) bad debt expense.” Despite the mandatory “shall,” Equitable has proposed no such offsets in this proceeding. The fact that these regulations are pending is inapposite to their applicability to Equitable. The pending regulations do not impose new requirements, but simply further implement the requirements first articulated by the Commission in its October 2006 Final Investigatory Order in Docket M-00051923.

G. Summary of Modifications to Universal Service Cost Recovery.

Q. CAN YOU SUMMARIZE AND CONSOLIDATE THE PROPOSED ADJUSTMENTS YOU MAKE TO THE COMPANY’S COST RECOVERY PROPOSAL?

A. Yes. Schedule RDC-5 presents a side-by-side comparison of my calculation of universal service costs (with cost offsets) to the universal service costs proposed by the Company in Attachment JMQ-2. The Rider D cost recovery I propose for Equitable Gas is \$1.0498 per MCF.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, :
 :
 v. : Docket No. R-2008-2029325, et al
 :
 Equitable Gas Company :
 :
 :
 :
 Independent Oil and Gas Association of :
 Pennsylvania :
 v. : C-20066800
 Equitable Gas Company :

SCHEDULES AND
ATTACHMENT TO THE
DIRECT TESTIMONY OF
ROGER D. COLTON

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

October 8, 2008

Schedule RDC-1

Difference Between Equitable Gas Calculation of CAP Commodity Revenue and Colton Calculation of Commodity Revenue (2008)				
	Rates	Colton	Equitable /a/	Difference
Bills per year		204,885	227,712	
Consumption per bill		11.1	11.1	
Total consumption		2,274,224	2,528,051	
Commodity charge	\$2.523	\$5,737,866	\$6,378,273	
Rider C Transition charge	\$0.227	\$516,249	\$573,868	
Natural gas supply	\$13.970	\$31,770,902	\$35,316,872	
Balance Charge	\$0.180	\$409,360	\$455,049	
Total commodity charge		\$38,434,377	\$42,724,062	\$4,289,685
NOTES:				
/a/ JMQ-2.				

Universal Service Costs to be Recovered Prior to Offsets (Colton)				
1	Service charge revenue	\$2,386,916		
2	Commodity charge revenue	\$38,434,377		
3	Total revenue (sum 1 + 2)	\$40,821,293		
4	Customer payments (No. of bills x payment per bill)	\$16,948,087	204,885 /a/	\$82.72 /b/
5	Total CAP shortfall (100%) (3 – 4)	\$23,873,206		
6	Actual shortfall payment rate	74%		
7	Actual shortfall payment amount (5 x 6) /c/	\$17,666,172		
8	Arrearage forgiveness	\$780,397		
9	LIURP	\$698,139		
10	Total Universal Service Costs (sum 7 + 8 + 9)	\$19,144,708		

NOTES:

/a/ Number of bills rendered to CAP customers.

/b/ Average payment per CAP bill rendered.

/c/ No STAS adjustment has been applied to this figure.

Schedule RDC-3

Side by Side Comparison of Company's Universal Service Cost Proposal and Colton's Universal Service Cost Proposal
(without cost offsets)

	Company proposal (JMQ-2)	Colton proposal (consolidated adjustments)
Customer charge revenue	\$2,652,845	\$2,386,916
Commodity charge revenue	\$42,724,062	\$38,434,377
STAS	(\$40,839)	(\$36,739)
Total Rate RS	\$45,336,068	\$40,784,554
Customer payments (including LIHEAP)	\$18,837,122	\$16,948,087
CAP shortfall	\$26,498,946	\$23,836,467
Adjust for CAP credits not paid (74%)	\$26,498,946	\$17,638,985
CAP arrearage forgiveness	\$780,397	\$780,397
LIURP	\$698,139	\$698,139
CAP administrative costs	\$299,194	\$0
Total CAP/LIURP Costs to be recovered	\$28,276,676	\$19,117,521
Existing universal service funding	\$11,401,984	\$11,401,984
Increase in universal service funding	\$16,874,692	\$7,715,537
Bad debt offsets	\$0	\$0
Working capital offset	\$0	\$0
Total CAP/LIURP costs to be recovered (no offsets)	\$28,276,676	\$19,117,521
Normalized non-CAP residential throughput	19,658,593	19,658,593
Proposed Rider D Rate	\$1.4384	\$0.9725
Current funding	\$11,401,984	\$11,401,984
Increase in funding	\$16,874,692	\$7,715,537

Schedule RDC-4

Working Capital on Avoided Bad Debt From CAP Credits and Arrearage Forgiveness (Equitable Gas) (2008)

		Bills Behind				
	From Invoice Date to Bill Due Date	1	2	3	4	5
Arrears	\$1,000.00	\$200	\$200	\$200	\$200	\$200
<i>Incremental age to disconnection (5 months total)</i>	15	15	45	75	105	135
<i>Age after disconnection (1 months total)</i>		60	60	60	60	60
Dollar Lag Days	135,000	15,000	21,000	27,000	33,000	39,000
Annualized Weighted Return	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%
Gross Up Factor for Taxes	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Weighted Return (GUFT)	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%
Days per Year	365	365	365	365	365	365
Daily Return (GUFT)	0.0288%	0.0288%	0.0288%	0.0288%	0.0288%	0.0288%
Working Capital	\$38.84	\$4.32	\$6.04	\$7.77	\$9.49	\$11.22
Annualized Working Capital per \$1,000	\$38.84					
WC per \$1 of CAP credits	\$0.0388					
WC offset (percentage)	3.88%					

Schedule RDC-5

Side by Side Comparison of Company's Universal Service Cost Proposal and Colton's Universal Service Cost Proposal
(with cost offsets)

	Company proposal (JMQ-2)	Colton proposal (consolidated adjustments)
Customer charge revenue	\$2,652,845	\$2,386,916
Commodity charge revenue	\$42,724,062	\$38,434,377
STAS	(\$40,839)	(\$36,739)
Total Rate RS	\$45,336,068	\$40,784,554
Customer payments (including LIHEAP)	\$18,837,122	\$16,948,087
CAP shortfall	\$26,498,946	\$23,836,467
Adjust for CAP credits not paid (74%)	\$26,498,946	\$17,638,985
CAP arrearage forgiveness	\$780,397	\$780,397
LIURP	\$698,139	\$698,139
CAP administrative costs	\$299,194	\$0
Total CAP/LIURP Costs to be recovered	\$28,276,676	\$19,117,521
Existing universal service funding	\$11,401,984	\$11,401,984
Increase in universal service funding	\$16,874,692	\$7,715,537
Bad debt offsets (15.83%)	\$0	(\$1,221,370)
Working capital offset (3.88%)	\$0	(\$299,363)
Total CAP/LIURP costs to be recovered	\$28,276,676	\$20,638,254
Normalized non-CAP residential throughput	19,658,593	19,658,593
Proposed Rider D Rate	\$1.4384	\$1.0498
Current funding	\$11,401,984	\$11,401,984
Increase in funding	\$16,874,692	\$9,236,270

Attachment RC-1

ROGER D. COLTON

BUSINESS ADDRESS:

Fisher Sheehan & Colton
Public Finance and General Economics
34 Warwick Road, Belmont, MA 02478
617-484-0597 (voice) *** 617-484-0594 (fax)
roger@fsconline.com (e-mail)
<http://www.fsconline.com> (www address)

EDUCATION:

J.D. (Order of the Coif), University of Florida (1981)

M.A. (Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975)

PROFESSIONAL EXPERIENCE:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 - present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including: regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than three dozen states. He is particularly noted for creative program design and implementation within tight budget constraints.

National Consumer Law Center (NCLC): 1986 - 1994

As a staff attorney with NCLC, Colton worked on low-income energy and utility issues. He pioneered cost-justifications for low-income affordable energy rates, as well as developing models to quantify the non-energy benefits (e.g., reduced credit and collection costs, reduced working capital) of low-income energy efficiency. He designed and implemented low-income affordable rate and fuel assistance programs across the country. Colton was charged with developing new practical and theoretical underpinnings for solutions to low-income energy problems.

Community Action Research Group (CARG): 1981 - 1985

As staff attorney for this non-profit research and consulting organization, Colton worked primarily on energy and utility issues. He provided legal representation to low-income persons on public utility issues; provided legal and technical assistance to consumer and labor organizations; and provided legal and technical assistance to a variety of state and local governments nationwide on natural gas, electric, and telecommunications issues. He routinely appeared as an expert witness before regulatory agencies and legislative committees regarding energy and telecommunications issues.

PROFESSIONAL AFFILIATIONS:

Member: Board of Directors, Belmont Housing Trust, Inc.
Member: Advisory Board: Fair Housing Center of Greater Boston.
Past Member: Fair Housing Committee, Town of Belmont (MA)
Past Member: Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member: Board of Directors, Vermont Energy Investment Corporation.
Past Member: Board of Directors, National Fuel Funds Network
Past Member: National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member: Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member: ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member: National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member: National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

PROFESSIONAL ASSOCIATIONS:

National Association of Housing and Redevelopment Officials (NAHRO)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)
International Society for Policy Studies
Association for Social Economics

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COLTON EXPERIENCE AS EXPERT WITNESS

1988 - PRESENT

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O Equitable Gas Company	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	08
I/M/O Columbia Gas Company	Witness	Office of Ohio Consumers' Counsel	Rate design	Ohio	08
I/M/O Dominion East Ohio Gas Company	Witness	Office of Ohio Consumers' Counsel	Rate design	Ohio	08
I/M/O Vectren Energy Delivery Company	Witness	Office of Ohio Consumers' Counsel	Rate design	Ohio	08
I/M/O Public Service Company of North Carolina	Witness	NC Department of Justice	Rate design	North Carolina	08
I/M/O Piedmont Natural Gas Company	Witness	NC Department of Justice	Rate design	North Carolina	08
I/M/O National Grid	Witness	New Hampshire Legal Assistance	Low-income rate assistance	New Hampshire	08
I/M/O EmPower Maryland	Witness	Office of Peoples Counsel	Low-income energy efficiency	Maryland	08
I/M/O Duke Energy Carolinas Save-a-Watt Program	Witness	NC Equal Justice Foundation	Low-income energy efficiency	North Carolina	08
I/M/O Zia Natural Gas Company	Witness	Community Action New Mexico	Low-income/low-use rate design	New Mexico	08
I/M/O Universal Service Fund Support for the Affordability of Local Rural Telecomm Service	Witness	Office of Consumer Advocate	Telecomm service affordability	Pennsylvania	08 - 09
I/M/O Philadelphia Water Department	Witness	Public Advocate	Credit and Collections	Philadelphia	08
I/M/O Portland General Electric Company	Witness	Community Action--Oregon	General rate case	Oregon	08
I/M/O Philadelphia Electric Company (electric)	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	08
I/M/O Philadelphia Electric Company (gas)	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	08
I/M/O Columbia Gas Company	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	08
I/M/O Public Service Company of New Mexico	Witness	Community Action New Mexico	Fuel adjustment clause	New Mexico	08
I/M/O Petition of Direct Energy for Low-Income Aggregation	Witness	Office of Peoples Counsel	Low-income electricity aggregation	Maryland	07
I/M/O Office of Consumer Advocate et al. v. Verizon and Verizon North	Witness	Office of Consumer Advocate	Lifeline telecommunications rates	Pennsylvania	07
I/M/O Pennsylvania Power Company	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	07
I/M/O National Fuel Gas Distribution Corporation	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	07
I/M/O Public Service of New Mexico--Electric	Witness	Community Action New Mexico	Low-income programs	New Mexico	07

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O Citizens Gas/NIPSCO/Vectren for Universal Service Program	Witness	Citizens Gas & Coke Utility/Northern Indiana Public Service/Vectren Energy	Low-income program design	Indiana	07
I/M/O PPL Electric	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	07
I/M/O Section 15 Challenge to NSPI Rates	Witness	Energy Affordability Coalition	Discrimination in utility regulation	Nova Scotia	07
I/M/O Philadelphia Gas Works	Witness	Office of Consumer Advocate	Low-income and residential collections	Pennsylvania	07
I/M/O Equitable Gas Company	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	07
I/M/O Section 11 Proceeding, Energy Restructuring	Witness	Office of Peoples Counsel	Low-income needs and responses	Maryland	06
I/M/O Citizens Gas/NIPSCO/Vectren for Universal Service Program	Witness	Citizens Gas & Coke Utility/Northern Indiana Public Service/Vectren Energy	Low-income program design	Indiana	06
I/M/O Public Service Co. of North Carolina	Witness	North Carolina Attorney General/Dept. of Justice	Low-income energy usage	North Carolina	06
I/M/O Electric Assistance Program	Witness	New Hampshire Legal Assistance	Electric low-income program design	New Hampshire	06
I/M/O Verizon Petition for Alternative Regulation	Witness	New Hampshire Legal Assistance	Basic local telephone service	New Hampshire	06
I/M/O Pennsylvania Electric Co/Metropolitan Edison Co.	Witness	Office of Consumer Advocate	Universal service cost recovery	Pennsylvania	06
I/M/O Duquesne Light Company	Witness	Office of Consumer Advocates	Universal service cost recovery	Pennsylvania	06
I/M/O Natural Gas DSM Planning	Witness	Low-Income Energy Network	Low-income DSM program.	Ontario	06
I/M/O Union Gas Co.	Witness	Action Centre for Tenants Ontario (ACTO)	Low-income program design	Ontario	06
I/M/O Public Service of New Mexico merchant plant	Witness	Community Action New Mexico	Low-income energy usage	New Mexico	06
I/M/O Customer Assistance Program design and cost recovery	Witness	Office of Consumer Advocate	Low-income program design	Pennsylvania	06
I/M/O NIPSCO Proposal to Extend Winter Warmth Program	Witness	Northern Indiana Public Service Company	Low-income energy program evaluation	Indiana	05
I/M/O Piedmont Natural Gas	Witness	North Carolina Attorney General/Dept. of Justice	Low-income energy usage	North Carolina	05
I/M/O PSEG merger with Exelon Corp.	Witness	Division of Ratepayer Advocate	Low-income issues	New Jersey	05
Re. Philadelphia Water Department	Witness	Public Advocate	Water collection factors	Philadelphia	05
I/M/O statewide natural gas universal service program	Witness	New Hampshire Legal Assistance	Universal service	New Hampshire	05
I/M/O Sub-metering requirements for residential rental properties	Witness	Tenants Advocacy Centre of Ontario	Sub-metering consumer protections	Ontario	05

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O National Fuel Gas Distribution Corp	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	05
I/M/O Nova Scotia Power, Inc.	Witness	Dalhousie Legal Aid Service	Universal service	Nova Scotia	04
I/M/O Lifeline Telephone Service	Witness	National Ass'n State Consumer Advocates (NASUCA)	Lifeline rate eligibility	FCC	04
Mackay v. Verizon North	Witness	Office of Consumer Advocate	Lifeline rates—vertical services	Pennsylvania	04
I/M/O Philadelphia Gas Works	Witness	Office of Consumer Advocate	Credit and collections	Pennsylvania	04
I/M/O Citizens Gas & Coke/Vectren	Witness	Citizens Action Coalition of Indiana	Universal service	Indiana	04
I/M/O PPL Electric Corporation	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	04
I/M/O Consumers New Jersey Water Company	Witness	Division of Ratepayer Advocate	Low-income water rate	New Jersey	04
I/M/O Washington Gas Light Company	Witness	Office of Peoples Counsel	Low-income gas rate	Maryland	04
I/M/O Washington Gas Light Company	Witness	Office of Peoples Counsel	Low-income gas rate	Maryland	03
Golden v. City of Columbus	Witness	Helen Golden	ECOA disparate impacts	Ohio	02
Huegel v. City of Easton	Witness	Phyllis Huegel	Credit and collection	Pennsylvania	02
I/M/O Universal Service Fund	Witness	Public Utility Commission staff	Universal service funding	New Hampshire	02
I/M/O Philadelphia Gas Works	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	02
I/M/O Washington Gas Light Company	Witness	Office of Peoples Counsel	Rate design	Maryland	02
I/M/O Consumers Illinois Water Company	Witness	Illinois Citizens Utility Board	Credit and collection	Illinois	02
I/M/O Public Service Electric & Gas Rates	Witness	Division of Ratepayer Advocate	Universal service	New Jersey	01
I/M/O Pennsylvania-American Water Company	Witness	Office of Consumer Advocate	Low-income rates and water conservation	Pennsylvania	01
I/M/O Louisville Gas & Electric Prepayment Meters	Witness	Kentucky Community Action Association	Low-income energy	Kentucky	01
I/M/O NICOR Budget Billing Plan Interest Charge	Witness	Cook County State's Attorney	Rate Design	Illinois	01
I/M/O Rules Re. Payment Plans for High Natural Gas Prices	Witness	Cook County State's Attorney	Budget Billing Plans	Illinois	01
I/M/O Philadelphia Water Department	Witness	Office of Public Advocate	Credit and collections	Philadelphia	01
I/M/O Missouri Gas Energy	Witness	Office of Peoples Counsel	Low-income rate relief	Missouri	01
I/M/O Bell Atlantic--New Jersey Alternative Regulation	Witness	Division of Ratepayer Advocate	Telecommunications universal service	New Jersey	01

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O T.W. Phillips Gas and Oil Co.	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O Peoples Natural Gas Company	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O UGI Gas Company	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O PFG Gas Company	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
Armstrong v. Gallia Metropolitan Housing Authority	Witness	Equal Justice Foundation	Public housing utility allowances	Ohio	00
I/M/O Bell Atlantic--New Jersey Alternative Regulation	Witness	Division of Ratepayer Advocate	Telecommunications universal service	New Jersey	00
I/M/O Universal Service Fund for Gas and Electric Utilities	Witness	Division of Ratepayer Advocate	Design and funding of low-income programs	New Jersey	00
I/M/O Consolidated Edison Merger with Northeast Utilities	Witness	Save Our Homes Organization	Merger impacts on low-income	New Hampshire	00
I/M/O UtiliCorp Merger with St. Joseph Light & Power	Witness	Missouri Dept. of Natural Resources	Merger impacts on low-income	Missouri	00
I/M/O UtiliCorp Merger with Empire District Electric	Witness	Missouri Dept. of Natural Resources	Merger impacts on low-income	Missouri	00
I/M/O PacifiCorp	Witness	The Opportunity Council	Low-income energy affordability	Washington	00
I/M/O Public Service Co. of Colorado	Witness	Colorado Energy Assistance Foundation	Natural gas rate design	Colorado	00
I/M/O Avista Energy Corp	Witness	Spokane Neighborhood Action Program	Low-income energy affordability	Washington	00
I/M/O TW Phillips Energy Co.	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O PECO Energy Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O National Fuel Gas Distribution Corp.	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O PFG Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O UGI Energy Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
Re. PSCO/NSP Merger	Witness	Colorado Energy Assistance Foundation	Merger impacts on low-income	Colorado	99 - 00
I/M/O Peoples Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
I/M/O Columbia Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
I/M/O PG Energy Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
I/M/O Equitable Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
Alleruzzo v. Klarchek	Witness	Barlow Alleruzzo	Mobile home fees and sales	Illinois	99
I/M/O Restructuring New Jersey's Natural Gas Industry	Witness	Division of Ratepayer Advocate	Universal service	Pennsylvania	99
I/M/O Bell Atlantic Local Competition	Witness	Public Utility Law Project	Lifeline telecommunications rates	New Jersey	99

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O Merger Application for SBC and Ameritech Ohio	Witness	Edgemont Neighborhood Association	Merger impacts on low-income consumers	Ohio	98 - 99
Davis v. American General Finnce	Witness	Thomas Davis	Damages in "loan flipping" case	Ohio	98 - 99
Griffin v. Associates Financial Service Corp	Witness	Earlie Griffin	Damages in "loan flipping" case	Ohio	98 - 99
I/M/O Baltimore Gas and Electric Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
I/M/O Delmarva Power and Light Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
I/M/O Potomac Electric Power Co. Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
I/M/O Potomac Edison Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
VMHOA v. LaPierre	Witness	Vermont Mobile Home Owners Association	Mobile home tying	Vermont	98
Re. Restructuring Plan of Virginia Electric Power	Witness	VMH Energy Services, Inc.	Consumer protection/basic generation service	Virginia	98
Mackey v. Spring Lake Mobile Home Estates	Witness	Timothy Mackey	Mobile home fees	State ct. Illinois	98
Re. Restructuring Plan of Atlantic City Electric	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Re. Restructuring Plan of Jersey Central Power & Light	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Re. Restructuring Plan of Public Service Electric & Gas	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Re. Restructuring Plan of Rockland Electric	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Appleby v. Metropolitan Dade County Housing Agency	Witness	Legal Services of Greater Miami	HUD utility allowances	Fed. court: So. Florida	97 - 98
Re. Restructuring Plan of PECO Energy Company	Witness	Energy Coordinating Agency of Philadelphia	Universal service	Pennsylvania	97
Re. Atlantic City Electric Merger	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97
Re. IES Industries Merger	Witness	Iowa Community Action Association	Low-income issues	Iowa	97
Re. New Hampshire Electric Restructuring	Witness	NH Comm. Action Ass'n	Wires charge	New Hampshire	97
Re. Natural Gas Competition in Wisconsin	Witness	Wisconsin Community Action Association	Universal service	Wisconsin	96
Re. Baltimore Gas and Electric Merger	Witness	Maryland Office of Peoples Counsel	Low-income issues	Maryland	96
Re. Northern States Power Merger	Witness	Energy Cents Coalition	Low-income issues	Minnesota	96

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
Re. Public Service Co. of Colorado Merger	Witness	Colorado Energy Assistance Foundation	Low-income issues	Colorado	96
Re. Massachusetts Restructuring Regulations	Witness	Fisher, Sheehan & Colton	Low-income issues/energy efficiency	Massachusetts	96
Re. FERC Merger Guidelines	Witness	National Coalition of Low-Income Groups	Low-income interests in mergers	Washington D.C.	96
Re. Joseph Keliikuli III	Witness	Joseph Keliikuli III	Damages from lack of homestead	Honolulu	96
Re. Theresa Mahaulu	Witness	Theresa Mahaulu	Damages from lack of homestead	Honolulu	95
Re. Joseph Ching, Sr.	Witness	Re. Joseph Ching, Sr.	Damages from lack of homestead	Honolulu	95
Joseph Keaulana, Jr.	Witness	Joseph Keaulana, Jr.	Damages from lack of homestead	Honolulu	95
Re. Utility Allowances for Section 8 Housing	Witness	National Coalition of Low-Income Groups	Fair Market Rent Setting	Washington D.C.	95
Re. PGW Customer Service Tariff Revisions	Witness	Philadelphia Public Advocate	Credit and collection	Philadelphia	95
Re. Customer Responsibility Program	Witness	Philadelphia Public Advocate	Low-income rates	Philadelphia	95
Re. Houston Lighting and Power Co.	Witness	Gulf Coast Legal Services	Low-Income Rates	Texas	95
Re. Request for Modification of Winter Moratorium	Witness	Philadelphia Public Advocate	Credit and collection	Philadelphia	95
Re. Dept of Hawaii Homelands Trust Homestead Production	Witness	Native Hawaiian Legal Corporation	Prudence of trust management	Honolulu	94
Re. SNET Request for Modified Shutoff Procedures	Witness	Office of Consumer Counsel	Credit and collection	Connecticut	94
Re. Central Light and Power Co.	Witness	United Farm Workers	Low-income rates/DSM	Texas	94
Blackwell v. Philadelphia Electric Co	Witness	Gloria Blackwell	Role of shutoff regulations	Penn. courts	94
U.S. West Request for Waiver of Rules	Witness	Wash. Util. & Transp. Comm'n Staff	Telecommunications regulation	Washington	94
Re. U.S. West Request for Full Toll Denial	Witness	Colorado Office of Consumer Counsel	Telecommunications regulation	Colorado	94
Washington Gas Light Company	Witness	Community Family Life Services	Low-income rates & energy efficiency	Washington D.C.	94
Clark v. Peterborough Electric Utility	Witness	Peterborough Community Legal Centre	Discrimination of tenant deposits	Ontario, Canada	94
Dorsey v. Housing Auth. of Baltimore	Witness	Baltimore Legal Aide	Public housing utility allowances	Federal district court	93
Penn Bell Telephone Co.	Witness	Penn. Utility Law Project	Low-income phone rates	Pennsylvania	93
Philadelphia Gas Works	Witness	Philadelphia Public Advocate	Low-income rates	Philadelphia	93
Central Maine Power Co.	Witness	Maine Assn Ind. Neighborhoods	Low-income rates	Maine	92
New England Telephone Company	Witness	Mass Attorney General	Low-income phone rates	Massachusetts	92
Philadelphia Gas Co.	Witness	Philadelphia Public Advocate	Low-income DSM	Philadelphia	92

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
Philadelphia Water Dept.	Witness	Philadelphia Public Advocate	Low-income rates	Philadelphia	92
Public Service Co. of Colorado	Witness	Land and Water Fund	Low-income DSM	Colorado	92
Sierra Pacific Power Co.	Witness	Washoe Legal Services	Low-income DSM	Nevada	92
Consumers Power Co	Witness	Michigan Legal Services	Low-income rates	Michigan	92
Columbia Gas	Witness	Penn. State Office of Consumer Advocate (OCA)	Energy Assurance Program	Pennsylvania	91
Mass. Elec. Co.	Witness	Mass Elec Co.	Percentage of Income Plan	Massachusetts	91
AT&T	Witness	TURN	Inter-LATA competition	California	91
Generic Investigation into Uncollectibles	Witness	Penn OCA	Controlling uncollectibles	Pennsylvania	91
Union Heat Light & Power	Witness	Kentucky Legal Services (KLS)	Energy Assurance Program	Kentucky	90
Philadelphia Water	Witness	Philadelphia Public Advocate (PPA)	Controlling accounts receivable	Philadelphia	90
Philadelphia Gas Works	Witness	PPA	Controlling accounts receivable	Philadelphia	90
Mississippi Power Co.	Witness	Southeast Mississippi Legal Services Corp.	Formula ratemaking	Mississippi	90
Kentucky Power & Light	Witness	KLS	Energy Assurance Program	Kentucky	90
Philadelphia Electric Co.	Witness	PPA	Low-income rate program	Philadelphia	90
Montana Power Co.	Witness	Montana Ass'n of Human Res. Council Directors	Low-income rate proposals	Montana	90
Columbia Gas Co	Witness	Penn. OCA	Energy Assurance Program	Pennsylvania	90
Philadelphia Gas Works	Witness	PPA	Energy Assurance Program	Philadelphia	89
Southwestern Bell Telephone Co.	Witness	SEMLSC	Formula ratemaking	Mississippi	90
Generic Investigation into Low-income Programs	Witness	Vermont State Department of Public Service	Low-income rate proposals	Vermont	89
Generic Investigation into Demand Side Management Measures	Consultant	Vermont DPS	Low-income conservation programs	Vermont	89
National Fuel Gas	Witness	Penn OCA	Low-income fuel funds	Pennsylvania	89
Montana Power Co.	Witness	Human Resource Develop. Council District XI	Low-income conservation	Montana	88
Washington Water Power Co.	Witness	Idaho Legal Service Corp.	Rate base, rate design, cost-allocations	Idaho	88

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08

NBC PA

RIS

Pennsylvania Public Utility Commission,

v.

Equitable Gas Company

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:
:

Docket No. R-2008-2029325, et al

Independent Oil and Gas Association of
Pennsylvania

v.

Equitable Gas Company

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C-20066800

DIRECT TESTIMONY OF

ROGER D. COLTON

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

October 8, 2008

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1 **Q. PLEASE STATE YOUR NAME AND ADDRESS.**

2 A. My name is Roger Colton. My address is Fisher, Sheehan & Colton, Public Finance and
3 General Economics, 34 Warwick Road, Belmont, Massachusetts 02478.

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

5 A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General
6 Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a
7 variety of federal and state agencies, consumer organizations and public utilities on rate and
8 customer service issues involving telephone, water/sewer, natural gas and electric utilities.

9 **Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?**

10 A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA") of
11 Harrisburg, Pennsylvania.

12 **Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.**

13 A. I work primarily on low-income utility issues. This involves regulatory work on rate and
14 customer service issues, as well as research into low-income usage, payment patterns, and
15 affordability programs. At present, I am working on various projects in the states of New
16 Hampshire, Maryland, Pennsylvania, North Carolina, Ohio, Indiana, Iowa, Colorado, New
17 Mexico, Oregon and Washington. My clients include state agencies (*e.g.*, Pennsylvania
18 Office of Consumer Advocate, Maryland Office of Peoples Counsel, North Carolina
19 Department of Justice, Iowa Department of Human Rights), federal agencies (*e.g.*, U.S.
20 Department of Health and Human Services), community-based organizations (*e.g.*,
21 Community Action of New Mexico, Coalition to Keep Indiana Warm, Community Action
22 Partnership of Oregon), and private utilities (*e.g.*, Entergy Services, Citizens Gas and Coke
23 Utilities, Northern Indiana Public Service Company, Tacoma Public Utilities). In addition

1 to state- and utility-specific work, I engage in national work in the United States and
2 Canada. For example, I am currently working on a national study of the responses of water
3 utilities to the payment troubles of residential customers for the American Water Works
4 Association Research Foundation. In 2007, I was part of a team that performed a multi-
5 sponsor public/private national study of low-income energy assistance programs.

6 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

7 A. After receiving my undergraduate degree in 1975, I obtained further training in both law and
8 economics. I received my law degree in 1981; I received my Masters Degree (economics)
9 in 1993. A copy of my curriculum vitae is appended as Attachment RC-1.

10 **Q. HAVE YOU AUTHORED ARTICLES ON PUBLIC UTILITY REGULATORY**
11 **ISSUES?**

12
13 A. Yes. I have published more than 80 articles in scholarly and trade journals, primarily on
14 low-income utility and housing issues. I have published an equal number of technical
15 reports for various clients on energy, water, telecommunications and other associated low-
16 income utility issues. My publications are listed in Attachment RC-1.

17 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY**
18 **COMMISSIONS?**

19
20 A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PUC" or
21 "Commission") on a variety of low-income energy, water and telecommunication issues
22 over the past 20 years. In addition, I have testified in regulatory proceedings in more than
23 30 states and various Canadian provinces on a wide range of low-income water,
24 telecommunications and energy issues. Proceedings in which I have previously appeared as
25 an expert witness are listed in Attachment RC-1.
26

1 **Q. PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY.**

2 A. The purpose of my testimony is two-fold. First, I will review the reasonableness of the
3 universal service costs that Equitable Gas proposes to collect through its Rider D.
4 Second, I will assess the extent to which Equitable Gas has complied with the directives
5 of the Pennsylvania Public Utility Commission ("PUC") to calculate the cost-offsets to be
6 used in funding the Company's universal service programs.

7 **Part 1. The Company's Proposed Rider D Universal Service Cost Recovery.**

8 **Q. PLEASE EXPLAIN THE COSTS THAT EQUITABLE GAS PROPOSES TO**
9 **RECOVER THROUGH ITS "RIDER D."**

10
11 A. The Company proposes to recover the costs of its Customer Assistance Program ("CAP")
12 and LIURP programs through its Rider D. The Company proposes that Rider D be
13 implemented as a reconcilable surcharge imposed on residential non-CAP customers. On
14 an annual basis, the Company estimates what it expects to spend on its Universal Service
15 costs using both known and projected information. The Company then provides a
16 quarterly reconciliation of its actual expenditures to its expected expenditures. The
17 Company either returns over-expenditures to customers (with interest) or collects its
18 under-expenditures (also with interest). The objective, according to Company witness
19 Quinn, is to use the "best information available to minimize any over- or under-recovery
20 of actual universal service expenses." (Quinn Direct, at 30 – 31). The proposed Rider D
21 is similar to the current cost recovery mechanism for universal service costs with the
22 exception that Equitable does not currently reconcile the costs collected through its Rider
23 to its actual expenditures.
24

1 Q. GIVEN THE RECONCILIATION PROCESS, PLEASE EXPLAIN WHY IT IS
2 IMPORTANT TO MAKE THE CORRECTIONS TO THE CAP COST
3 RECOVERY YOU RECOMMEND BELOW.
4

5 A. In the case of Equitable's CAP administrative costs, I propose to take those costs out of
6 the reconcilable rate rider process. For the reasons I explain below, the CAP
7 administrative costs are most appropriately collected through base rates. Moreover, the
8 modifications I recommend below are based upon methodological flaws in estimating
9 CAP costs. While the reconciliation process for the prior period would return to
10 ratepayers the over-collection from that prior period, the methodological flaws would
11 result in the Company making the same over-estimation for the ensuing period. As a
12 result, ratepayers would effectively have a permanent loss of money. Finally, the
13 Company does not propose to recognize the cost offsets at all in the reconciliation
14 process. In each of these cases, the existence of the reconciliation process does not
15 adequately address the over-recovery of CAP costs.

16 Consider, for example, my recommended modifications concerning both the
17 *overstatement of the number of bills issued to CAP customers and the overstatement of*
18 *CAP credits that are paid to CAP customers.* While the reconciliation process for a prior
19 period may well reflect the over-recovery from that *prior* period, the estimates for the
20 *next* period would then be made based on the same methodology and would again result
21 in the same over-collection for the reasons I identify. As a result, even though each
22 period involves a reconciliation, the Company would permanently be in an over-
23 collection situation.
24

1 **Q. IS THERE A REASON WHY A PERMANENT OVER-COLLECTION**
2 **SITUATION IS NOT SOUND IF CUSTOMERS WILL BE MADE WHOLE FOR**
3 **PRIOR PERIOD OVER-COLLECTIONS?**

4
5 A. Yes. The permanent over-collection means that customers will never be completely
6 made whole. When an over-collection from the prior period is returned to customers, the
7 over-collection for the subsequent period is imposed. As a result, the Company will
8 permanently retain dollars that belong to the customers.

9 **Q. DOES THE COMPANY PROPOSE A SPECIFIC LEVEL OF ESTIMATED**
10 **UNIVERSAL SERVICE COSTS TO BE RECOVERED THROUGH ITS RIDER**
11 **D?**

12
13 A. Yes. In Attachment JMQ-2 to Company witness Quinn's testimony, the Company
14 identifies that it has total current funding for CAP and LIURP of \$11,401,984
15 (Attachment JMQ-2, Line 32). It projects total CAP/LIURP dollars to be recovered equal
16 to \$28,276,683. (Attachment JMQ-2, Line 27). Accordingly, the Company seeks an
17 *additional* \$16,874,700 in CAP/LIURP funding in this proceeding beyond that which is
18 already being collected in rates ($\$28,276,683 - \$11,401,984 = \$16,874,700$).

19 The proposed Rider D is designed to recover the entire \$28,276,683, not merely
20 the \$16,874,700 identified as new universal service funding needs in this proceeding. In
21 other words, Rider D is designed to collect \$28,276,683, which results in a charge of
22 \$1.4384 per MCF for residential, non-CAP customers (Attachment JMQ-2, Line 36).

23 **Q. DOES THE COMPANY CALCULATE THE COSTS TO BE RECOVERED**
24 **THROUGH ITS RIDER D IN AN APPROPRIATE FASHION?**

25
26 A. No. The Company overstates the costs that it should be allowed to recover through its
27 Rider D. Moreover, the Company fails to account for the expense offsets that provide for
28 universal service cost recovery outside of rates charged to customers. In this section of

1 my testimony, I will assess the extent to which Equitable overstates its universal service
2 costs.

3 **A. Number of CAP Bills.**

4 **Q. PLEASE EXPLAIN THE FIRST PROBLEM THAT YOU IDENTIFY IN THE**
5 **COMPANY'S ESTIMATION OF CAP COSTS TO BE RECOVERED THROUGH**
6 **RIDER D.**

7
8 A. The Company's estimate of CAP costs to be recovered through Rider D overstates the
9 number of monthly bills that the Company can be expected to issue to CAP customers
10 during the billing period.

11 **1. The Company Cost-Estimation Procedure.**

12 **Q. HOW DOES AN OVERSTATEMENT OF THE NUMBER OF CAP BILLS**
13 **AFFECT THE TOTAL CAP COSTS THAT THE COMPANY PROPOSES TO**
14 **RECOVER THROUGH RIDER D?**

15
16 A. The total CAP costs that the Company proposes to recover through Rider D is based on
17 the difference between what CAP participants pay under the Company's CAP program
18 and the revenue that would have been billed to those customers at standard residential
19 rates in the absence of the program. In other words, if the billed revenue at standard
20 residential rates is \$100, and the CAP payment is \$75, the "CAP shortfall" (or "CAP
21 credit") is \$25. It is that \$25 CAP credit that is then passed through Rider D to all other
22 residential ratepayers. Accordingly, should the Company overstate the revenue that
23 would have been billed at standard residential rates in the absence of the program, the
24 CAP shortfall will be overstated as well.

25 In the Company's estimating process, the estimated amount of revenue that would
26 have been billed in the absence of CAP is based upon the Company's projection of the

1 number of monthly bills it will render to CAP participants. As set forth in Company
2 Attachment JMQ-2, the Company engages in a two-step process:

3 ➤ First, the Company multiplies the number of bills by the monthly fixed
4 customer charge to obtain the amount of customer charge revenue that it
5 would have billed in the absence of CAP.

6 ➤ Second, the Company multiplies the number of bills by the average
7 consumption per bill to obtain the total consumption for its CAP population. It
8 then multiplies that total consumption by the various components of the
9 commodity price to obtain the amount of commodity revenue that it would
10 have billed in the absence of CAP.

11 Accordingly, if the Company overstates the number of bills that it expects to render to
12 CAP customers, it will overstate the revenue it would have expected to bill in the absence
13 of CAP. If the Company overstates the revenue it would have expected to bill in the
14 absence of CAP, it will, in turn, overstate the CAP shortfall that should be collected
15 through the Company's proposed Rider D.

16 In my testimony below, I explain the overstatement of the number of CAP bills,
17 along with the impact that overstatement has on the revenue the Company would have
18 expected to bill at standard rates in the absence of the CAP program.

19 **2. The Overstatement of the Number of Monthly CAP Bills.**

20 **Q. HOW DOES THE COMPANY OVERSTATE THE NUMBER OF BILLS IT**
21 **EXPECTS TO RENDER TO CAP CUSTOMERS?**

22
23 **A.** The Company estimates that it will render 227,712 bills to CAP participants. (Attachment
24 JMQ-2). It calculates that figure by assuming that the Company will have 18,976 CAP
25 participants. By multiplying that participation rate by 12 months, it derives its 227,712

1 figure (18,976 cap participants x 12 months = 227,712 monthly bills to CAP
2 participants).

3 **Q. IS THE COMPANY CORRECT IN USING A PARTICIPATION RATE OF 18,976**
4 **FOR PURPOSES OF ESTIMATING THE NUMBER OF BILLS IT WILL ISSUE**
5 **TO ITS CAP PARTICIPANTS?**
6

7 A. No. In using the 18,976 figure, the Company erroneously assumes that the CAP
8 participation rate will equal 18,976 throughout the year. That assumption is in error. The
9 Company will not average 18,976 full-time equivalent CAP participants in each month.

10 **Q. UPON WHAT DO YOU BASE THAT CONCLUSION?**

11 A. In response to OCA discovery requests, the Company provided a database with
12 comprehensive CAP data in it for all CAP participants for the months of January 2007
13 through July 2008. That database provides the monthly data of individual CAP
14 participants for, among other items, the total participants, current bills, total amount due
15 by month, total CAP credit granted, total arrearage forgiveness granted, and
16 consumption.

17 Based on my analysis of that data, I conclude that there will not be 18,976 full-
18 time equivalent CAP participants for the Company per month. I do not dispute the
19 Company's estimate of 18,976 as a *year-end* 2008 figure for total CAP participants
20 (Attachment JMQ-2). The Company indicates that it calculated the 18,976 number of
21 CAP participants by escalating the March 2008 number of participants by its 2007
22 growth patterns. (OTS-RE-122-D). I derived basically the same 19,000 participation
23 figure by escalating the January 2008 number of participants reported in the CAP
24 database provided in response to OCA discovery questions (OCA-V-12) (n=16,210) by
25 the rate of participation increase in 2007 (14%) reported in that same database.

1 To use a year-end number (i.e., a single point in time), however, to estimate the
2 total year-round full-time equivalent participants will overstate the total number of bills
3 rendered to CAP participants over the course of the year. By way of example, since the
4 year-end participation rate for 2007 was 16,210 CAP participants, using the Company's
5 methodology would have estimated a total of 194,520 monthly bills to CAP participants
6 for 2007. The *actual* number of bills rendered to CAP participants in 2007, however, was
7 only 182,510, a difference of nearly seven percent (7%).

8 **Q. WHAT DO YOU RECOMMEND WITH REGARD TO THE CALCULATION OF**
9 **THE PROJECTED NUMBER OF CAP BILLS THE COMPANY WILL**
10 **RENDER?**

11
12 A. I recommend that, rather than applying its escalation rate to derive a year-end number,
13 the Company apply its 14% growth rate to the 2007 average number of CAP participants
14 receiving bills (15,209) to estimate the number of full-time equivalent participants per
15 month for 2008. The projected number of estimated full-time equivalent participants
16 would thus be 17,338 ($15,209 \times 1.14 = 17,338$). Annualizing that figure to account for 12
17 monthly bills yields a total of 208,059 annual bills rather than the Company's estimated
18 227,712. It is this 208,059 figure that I use in my CAP cost calculations.

19 **Q. SHOULD THE COMPANY USE THIS METHODOLOGY IN ESTIMATING**
20 **FUTURE CAP COSTS FOR COLLECTION THROUGH RIDER D?**

21
22 A. Yes. In estimating CAP costs on a going-forward basis for purposes of calculating the
23 Rider D surcharge, I recommend that the Company begin with the number of average
24 full-time equivalent CAP participants, using the prior year as the base year (e.g., 2007
25 base for 2008 estimate; 2008 base for 2009 estimate). I recommend that that number of
26 full-time equivalent CAP participants per month then be escalated by the growth rate in
27 CAP participants during that base year. This determination of the estimated number of

CAP participants will affect the overall calculation of customer charge revenue, commodity revenue, and CAP payments.

Q. IS THERE A SECOND ADJUSTMENT YOU RECOMMEND BE MADE TO THE NUMBER OF BILLS TO BE USED IN CALCULATING CAP COSTS?

A. Yes. In discussing the Equitable Gas CAP program, there is a difference in the use of terminology that should be accounted for in the calculation of the Company's cost recovery through the proposed Rider D. The Company reports that it had 18,805 CAP "participants" in July 2008.¹ Merely because a customer is listed as a "CAP participant," however, does not mean that the customer received a CAP bill in that month. Only if a participant receives a CAP bill with usage charges does the customer receive a CAP credit. Only if a participant receives a CAP credit does the Company incur a CAP expense that is subject to recovery through Rider D.

According to the Company's database provided to OCA (OCA-V-12), during 2007, only 98.5% of customers listed as a "CAP participant" received a CAP bill that had usage associated with it. While the 1.5% difference may, at first glance, appear insubstantial, it yields a total number of bills rendered to CAP participants of 204,885 rather than the 208,059 calculated using the total number of full-time equivalent CAP participants discussed above. The financial impact is significant.

Q. DOES YOUR PROPOSED NUMBER OF BILLS RECOGNIZE THE FACT THAT THE COMPANY ALREADY REPORTS A JULY 2008 PARTICIPANT POPULATION OF 18,805?

A. Yes. While the database provided to OCA reveals only 18,602 CAP participants in July 2008, I understand that the Company reported a July 2008 participation rate of 18,805 in

¹ The database that the Company provided to OCA included only 18,602 participants in July 2008 (OCA-V-12).

1 response to discovery questions from the Office of Trial Staff ("OTS"). (OTS-RE-122-

2 D). I do not find either July 2008 number to be dispositive. Four reasons exist for this.

- 3 ➤ First, it is not the participation rate at any single point in time that is important
4 in calculating CAP expenses to be passed through Rider D. It is the
5 participation rate over the full year that is important. The full-time equivalent
6 participation rate is calculated by summing the total number of CAP monthly
7 bills and dividing that figure by 12. If I have 10 CAP participants for the first
8 six months of a year, and 20 CAP participants for the second six months, I do
9 not have annual expenses associated with 20 participants. I instead have
10 expenses associated with 15 full-time equivalent participants $((10*6) +$
11 $(20*6)) / 12 = 15$.
12
13 ➤ Second, merely because the CAP participation rate in July was 18,805 does
14 not mean that the participation rate will increase. According to the CAP
15 database provided by the Company to OCA (OCA-V-12), in 2007, for
16 example, the CAP participation rate did not consistently increase from month-
17 to-month. The Company had 15,532 participants in June 2007 and 15,524 in
18 July 2007. By September 2007, the number of participants had decreased to
19 15,143; the number of participants had further decreased to only 15,088 by
20 October 2007. Taking the July participation as a starting point, and escalating
21 the number of participants from that starting point, does not yield accurate
22 results.
23
24 ➤ Third, the adjustment for the number of CAP participants who do not receive
25 CAP bills would apply to the Company's reported July 2008 participation
26 figure as well. The Company's database provided to OCA reveals that 1.4%
27 of July customers reported as being "CAP participants" did not receive CAP
28 bills (or received CAP bills with no usage).
29
30 ➤ Finally, while a July participation rate of 18,805 may increase the total
31 number of full-time equivalent participants when combined with previous
32 months, it would not make the full-time equivalent number equal to that July
33 participation figure. For example, the database of CAP participant data
34 provided to OCA reports that the January 2008 number of CAP participants
35 receiving bills was only 16,202. (OCA-V-12). The 18,805 participation rate
36 must be blended with all other monthly participation rates to achieve a correct
37 annual cost estimate.
38

39 The estimates I set forth above are not inconsistent at all with the Company's reported

40 July 2008 participant population of 18,805.

1 **3. The Overstatement of Billings at Standard Residential Rates in the Absence of CAP.**

2 **Q. HOW DOES THE OVERSTATEMENT OF THE NUMBER OF BILLS TO CAP**
3 **PARTICIPANTS AFFECT THE CAP COST RECOVERY THROUGH RIDER D?**

4
5 A. As I explain in more detail above, Rider D is designed to compensate the Company for
6 the CAP credits (CAP shortfall) that the Company provides to CAP participants. The
7 CAP shortfall is the difference between what the Company would have billed at standard
8 residential rates and what the Company does, in fact, bill at CAP rates. To the extent that
9 the number of bills to CAP participants is overstated, the Company overstates the revenue
10 it would have billed at standard residential rates and would, therefore, also overstate the
11 CAP shortfall to be collected through Rider D. The overstatement of the number of bills
12 first affects the amount of revenue that the Company estimates it would have billed
13 through its fixed monthly customer charge. The overstatement of the number of bills also
14 affects the amount of commodity charge revenue the Company estimates it would have
15 billed in the absence of CAP.

16 **Q. WHAT IMPACT DOES THE OVERSTATEMENT OF THE NUMBER OF BILLS**
17 **RENDERED TO CAP PARTICIPANTS HAVE ON THE COMPANY'S**
18 **ESTIMATE OF WHAT REVENUE WOULD HAVE BEEN BILLED THROUGH**
19 **THE FIXED MONTHLY CUSTOMER CHARGE IN THE ABSENCE OF CAP?**

20
21 A. The Company's cost recovery estimates are based on an assumption that it will render
22 227,712 monthly bills to CAP participants (Attachment JMQ-2). Applying a fixed
23 customer charge of \$11.65 associated with each bill yields the Company's estimate of
24 \$2,652,845 in revenue that would have been billed to CAP participants at standard
25 residential rates (Attachment JMQ-2).

1 My two adjustments to the number of monthly bills to CAP participants are: (1) using the
2 number of full-time equivalent CAP participants for 2008 (208,059); and (2) adjusting for
3 those full-time equivalent CAP participants that do not receive a bill in a particular month
4 (1.5%). Applying these two adjustments yields a total number of bills of 204,885.
5 Applying the fixed monthly customer charge of \$11.65 to each bill yields an estimated
6 revenue of \$2,386,916 from fixed monthly customer charges at standard residential rates.
7 This is a reduction of \$265,929 in customer charge revenue from the Company's estimate
8 in Attachment JMQ-2.

9 **Q. DOES THE DIFFERENCE IN THE NUMBER OF BILLS RENDERED AFFECT**
10 **THE TOTAL CONSUMPTION UNDERLYING THE COMPANY'S CAP COST**
11 **ESTIMATE?**

12
13 A. Yes. The Company projects an annualized and normalized volume of gas consumption of
14 2,528,091 MCF for its CAP customers (Attachment JMQ-2). The Company derives this
15 consumption figure as follows:

- 16 ➤ The Company begins with its estimated participation rate of 18,976 CAP
17 participants (Attachment JMQ-2);
- 18 ➤ The Company projects an average annual consumption of 11.1 MCF per
19 billing month (Attachment JMQ-2);
- 20 ➤ The Company uses 12 bills per year for CAP participants.
- 21 ➤ Multiplying these factors yields the gas consumption of 2,528,091 MCF
22 (18,976 participants x 12 months per year = 227,712 monthly bills per year x
23 11.1 MCF monthly consumption per participant = 2,528,091 MCF total
24 annual CAP consumption).

1 I agree with that estimate. The database provided to OCA (OCA-V-12) yields an average
2 usage per billing month of 11.1 MCF for 2007 (some minor variation may occur due to
3 rounding).

4 As I describe in detail above, my *disagreement* lies with the number of bills that
5 the Company estimates as rendering for its CAP population. Rather than rendering
6 227,712 bills to CAP participants, the Company will instead render only 204,885 bills.
7 Accordingly, rather than having an annual consumption of 2,528,091 MCF, the Company
8 will have CAP consumption of only 2,274,224 MCF (204,885 monthly bills per year x
9 11.1 MCF monthly consumption per participant = 2,274,224 MCF total annual CAP
10 consumption).

11 **Q. WHAT IMPACT DOES THIS OVERSTATEMENT OF TOTAL CAP**
12 **CONSUMPTION HAVE ON THE COMPANY'S ESTIMATE OF WHAT REVENUE**
13 **WOULD HAVE BEEN BILLED THROUGH THE VARIOUS COMPONENTS OF THE**
14 **COMMODITY CHARGE IN THE ABSENCE OF CAP?**
15

16 A. The Company included four different components in the commodity charge it uses to
17 calculate total revenue that would have been billed to CAP participants at standard
18 residential rates in the absence of CAP: the delivery charge, the Rider C-Transition Cost,
19 the Natural Gas supply charge, and the balancing charge (Attachment JMQ-2). This
20 commodity charge is applied to the total consumption of CAP participants to derive the
21 revenue that would have been generated at standard residential rates in the absence of
22 CAP. The commodity charge, when added to the fixed monthly customer charge,
23 comprise the customer's total natural gas bill to Equitable at standard residential rates.

24 I identify in my discussion above why the Company has overstated its CAP
25 consumption, and how a reduced consumption level necessarily flows from the lower
26 number of bills that the Company will issue to CAP customers. Since the total

1 commodity charge is calculated by multiplying consumption times the rate, the use of a
2 lower consumption yields a total commodity charge of \$38,434,377 that would have been
3 billed to CAP customers at standard residential rates in the absence of the CAP. I have set
4 forth the calculation of the commodity charge in Schedule RDC-1, which is attached to
5 my testimony below. This figure stands in contrast to the Company's projected
6 \$42,724,062 (Attachment JMQ-2) from commodity charges.

7 **Q. CAN YOU SUMMARIZE THE ADJUSTMENTS YOU MAKE?**

8 A. Yes. The CAP credit (CAP shortfall) is the difference between what would have been
9 billed to CAP participants at standard residential rates and what is actually billed to CAP
10 participants under the CAP program. To the extent that the Company over-estimates the
11 revenue that would have been billed at standard residential rates, it will thus also over-
12 estimate the CAP shortfall. The two differences I identify are:

- 13 ➤ The Company estimates that it will bill \$2,652,845 in fixed monthly customer
14 charges in the absence of CAP, while I estimate that the Company will bill
15 \$2,386,916 in fixed monthly customer charges in the absence of CAP.
- 16 ➤ The Company estimates that it will bill \$42,724,062 in commodity charges at
17 standard residential rates in the absence of CAP (Attachment JMQ-2), while I
18 estimate that the Company will bill \$38,434,377 in commodity revenue in the
19 absence of CAP.

20 Combining these two bill components (fixed monthly customer charge + commodity
21 charge), the Company estimates that it will bill \$45,336,068 in total billings (net of
22 STAS) at standard residential rates in the absence of CAP, while I estimate that the
23 Company will bill \$40,784,554 (net of STAS) at standard residential rates in the absence

1 of CAP. This reduction of \$4,551,514 in billed revenue at standard residential rates in
2 the absence of CAP results in a reduction to the CAP credits to be passed through the
3 Company's Rider D.

4 **B. CAP Credits.**

5 **Q. WHAT IS THE THIRD ERROR THE COMPANY MAKES IN ITS PROPOSED**
6 **RIDER D COST RECOVERY CALCULATION?**

7
8 A. The Company overstates the CAP shortfall that it seeks to claim through its Rider D. The
9 Company identifies a CAP shortfall of \$26,498,953 (Attachment JMQ-2) to be collected
10 through its proposed Rider D. It estimates this shortfall by estimating the total bill
11 rendered to CAP customers at standard residential rates and subtracting the estimated
12 CAP customer payments (including LIHEAP payments). The sum of the CAP shortfall
13 plus the customer payments equals the total bill rendered to CAP customers at standard
14 residential rates.

15 The calculation that underlies the Company's proposed Rider D cost recovery
16 assumes, however, that CAP customers will make 100% of their payments and will,
17 accordingly, receive 100% of their CAP credits. Under the Equitable Gas program, a
18 CAP participant does not receive his or her CAP credit unless and until that participant
19 makes full payment of the CAP payment requirement. Since fewer than 100% of CAP
20 payments are made by CAP participants, the Company grants less than 100% of the CAP
21 credits that are potentially available.

22 **Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT FEWER THAN**
23 **100% OF CAP BILLS ARE ACTUALLY PAID?**

24
25 A. In the database provided by the Company in response to OCA discovery (OCA-V-12),
26 two of the elements that were included were the CAP budget amount billed each month

1 to CAP participants and the amount of the CAP customer payment that was actually
2 made. A third element provided in that database was the total amount due in any given
3 month by a CAP participant. That total amount due would include the current month's
4 CAP budget amount plus any unpaid budget amount from a prior month. In the twelve
5 months ending December 2007, the Company issued 182,510 bills to CAP customers,
6 and received 129,023 payments toward those bills (70.7% collection rate). In the twelve
7 months ending July 2008, the Company issued 203,989 bills to CAP participants and
8 received 142,651 payments toward those bills (69.9% collection rate). Clearly, the
9 Company's calculation based upon a 100% payment success rate overstates the CAP
10 credits that the Company will grant.

11 **Q. HAVE YOU ESTIMATED THE EXTENT TO WHICH THE COMPANY'S**
12 **PAYMENT OF CAP CREDITS IS OVERSTATED?**

13
14 **A.** Yes. I estimated the total dollars in CAP credits that were potentially payable by
15 subtracting the total CAP budget amount billed to CAP participants from the total bill for
16 current usage for the same time period. I then compared the actual dollars in CAP credits
17 granted during the same twelve-month period. By summing the total bill for current
18 usage for CAP participants in the database provided to OCA (OCA-V-12), I found that
19 the total bill for current usage was \$26,473,447 for the twelve month period ending
20 December 2007. By summing the total dollars of CAP bills rendered to the same
21 population, I found that the total CAP bill was \$13,812,012. By subtracting the total
22 dollars of CAP bills from the total dollars of bills for current usage at standard residential
23 rates, I found a potential CAP credit of \$12,661,435 had 100% of CAP budget amounts
24 been paid ($\$26,473,447 - \$13,812,012 = \$12,661,435$).

1 However, when I summed the total dollars of CAP credits the Company actually
2 granted for those customers, I found that the Company actually granted only \$9,373,863
3 in CAP credits in the same time period, which was only 74% of the total potential CAP
4 credits. Similarly, using the CAP database provided to OCA (OCA-V-12), and using the
5 same methodology, I found that in the twelve months ending July 2008, the total bill for
6 current usage was \$32,904,739, yielding a potential CAP credit of \$17,249,865.
7 However, the Company granted \$12,493,059 in CAP credits, or 72.4% of the total
8 potential CAP credits. Over the 18-month period of January 2007 through July 2008, the
9 Company granted \$20,262,662 in actual CAP credits out of a potential \$27,411,182
10 (73.9%).

11 **Q. HOW DO YOU RECONCILE THE FACT THAT ONLY APPROXIMATELY**
12 **70% OF THE PAYMENTS WERE MADE BUT MORE THAN**
13 **APPROXIMATELY 70% OF THE POTENTIALLY AVAILABLE CREDITS**
14 **WERE GRANTED?**

15
16 A. Equitable Gas grants its CAP credits when the full payment of a CAP bill is made. A
17 customer is thus able to “cure” his or her missed CAP payment from a prior month. If a
18 customer makes his or her June/July payments in July, the customer would have made
19 one payment but earned two months of CAP credit. Therefore, there is no inconsistency
20 in these two numbers.

21 **Q. WHAT ADJUSTMENT DO YOU RECOMMEND BE MADE TO THE**
22 **COMPANY’S PROPOSED RIDER D BASED ON THE COMPANY’S**
23 **OVERSTATEMENT OF THE PAYMENT OF CAP CREDITS?**

24
25 A. Based on the 74% payment rate of CAP credits (rounded up from 73.9%), I have reduced
26 the CAP shortfall subject to recovery by 26%. Before making this adjustment, I calculate
27 a total level of CAP credits of \$23,836,467 assuming that 100% of CAP credits were
28 granted (\$40,821,923 in bills at standard residential rates - \$16,948,087 in CAP customer

1 payments = \$23,836,467 in total CAP shortfall [net of STAS]]. The impact of my
2 adjustment yields a reduction in CAP credits actually granted of \$6,197,481 ($\$23,836,467$
3 $\times (1 - 0.74) = \$6,197,481$).

4 **Q. CAN YOU SUMMARIZE AND CONSOLIDATE THE TOTAL ADJUSTMENTS**
5 **TO THE COMPANY'S RIDER D COST CALCULATION BASED ON YOUR**
6 **DISCUSSION ABOVE?**

7
8 A. Yes. My consolidated cost recovery figure, before calculating offsets, is set forth in
9 Schedule RDC-2. The figure is calculated using the following inputs:

10 ➤ The total billed revenue is calculated as described above, yielding billed
11 revenue of \$40,821,923 (Schedule RDC-2, Line 3).

12 ➤ I estimate an actual individual per-customer payment (including LIHEAP
13 payments) of \$82.72 per bill. This calculation uses the Company's own per-
14 customer payment figure ($\$18,837,172$ total payments / $227,712$ monthly bills
15 $= \$82.72$ customer payment per bill). (Equitable Gas Attachment JM-Q-2).

16 ➤ I estimate total customer payments of \$16,948,087 ($\$82.72/\text{bill} \times 204,885$
17 bills) (Schedule RDC-2, Line 4).

18 ➤ I estimate the total CAP shortfall (using the Company's incorrect assumption
19 of a 100% payment rate) of \$23,873,206 ($\$40,821,923 - \$16,948,087$)
20 (Schedule RDC-2, Line 5).

21 ➤ I estimate the total CAP shortfall actually granted (and thus subject to cost
22 recovery) at \$17,666,172 ($\$23,873,206 \times 0.74 = \$17,666,172$) (Schedule
23 RDC-2, Line 7).

24 ➤ I exclude administrative expenses (which are discussed later in my testimony).

➤ I accept the CAP arrearage forgiveness costs of \$780,397 (Schedule RDC-2, Line 8).

➤ I accept the LIURP costs of \$698,139 (Schedule RDC-2, Line 9).

Based on these calculations, I recommend total CAP/LIURP costs to be recovered of \$19,144,708 before offsets (Schedule RDC-2, Line 10). A side-by-side comparison of the Company's proposed universal service cost recovery, and my proposed universal service cost-recovery (without offsets) is set forth in Schedule RDC-3.

The offsets required, however, before a final Rider D amount to be charged residential customers are discussed below.

D. Removal of CAP Administrative Costs from the Rider D Surcharge.

Q. WHAT EXPENSES SHOULD THE COMPANY RECOVER THROUGH ITS UNIVERSAL SERVICE RIDER?

A. The Company should collect the incremental expenses that are directly attributable to its universal service program through its proposed Rider D. Expenses that are not specifically universal service expenses, as well as expenses that are not incremental in nature, should not be recovered through Rider D. An incremental expense is one that the Company would not have incurred but for the universal service program.

Q. DOES THE COMPANY PROPOSE TO USE RIDER D TO RECOVER EXPENSES THAT ARE NEITHER INCREMENTAL NOR INCURRED SPECIFICALLY AS A RESULT OF ITS UNIVERSAL SERVICE PROGRAM?

A. Yes. The Company proposes to collect \$299,184 in CAP administrative expenses through its Rider D (Attachment JMQ-2). Administrative costs include a portion of its customer call center costs allocated to CAP along with certain staff costs described below. The Company's administrative expenses should be excluded from recovery through Rider D because these expenses are not incremental universal service expenses.

1 **Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT THE EQUITABLE**
2 **GAS CAP ADMINISTRATIVE EXPENSES ARE NOT INCREMENTAL**
3 **EXPENSES ATTRIBUTABLE TO THE CAP PROGRAM?**

4
5 A. The Company has three basic universal service staff positions: the EAP Administrator,
6 the Manager of Universal Service and Community Outreach ("Manager"), and the
7 Universal Service Associate ("Associate"). The Company has previously acknowledged
8 that the Manager and Associate positions are not positions created exclusively for the
9 CAP, but rather are job positions shared between CAP and non-CAP responsibilities.
10 Equitable could not identify what salaries and benefits are recovered as a universal
11 service cost. The Company should recover these administrative expenses through its base
12 rates, not through Rider D.

13 **Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT THE EQUITABLE**
14 **GAS CAP ADMINISTRATIVE EXPENSES ATTRIBUTED TO CAP**
15 **ENROLLMENT ARE NOT APPROPRIATELY RECOVERED THROUGH**
16 **RIDER D AS A CAP ADMINISTRATIVE EXPENSE?**

17
18 A. Because CAP enrollment expenses are not incremental universal service expenses, they
19 should not be recovered through Rider D. The CAP enrollment process was transitioned
20 *from community-based organizations to the Company call center in October 2006.* The
21 entire call center was outsourced to a third party in August 2006. The treatment of CAP
22 calls are rolled in with other customer service calls at the call center. The overall call
23 center expenses do not vary based on CAP enrollment activity. As can be seen, these call
24 center expenses are not incremental expenses attributable to the Company's universal
25 service programs. These expenses would be incurred regardless of whether CAP existed
26 or not. Accordingly, the expenses associated with the call center are base rate expenses.
27 They would be inappropriate to recover through Rider D.

1 **Q. HOW SHOULD EQUITABLE RECOVER ITS CAP ADMINISTRATIVE**
2 **EXPENSES?**

3
4 A. Equitable proposes to recover \$299,194 in administrative expenses through its Rider D. I
5 propose that this total of \$299,194 be excluded from recovery through Rider D. They
6 should instead be recovered through base rates.

7 **Q. IN PROPOSING TO EXCLUDE THESE EXPENSES FROM THE**
8 **RECONCILABLE RIDER, DO YOU DENY THE COMPANY ITS ABILITY TO**
9 **HAVE THESE EXPENSES FULLY RECOVERED?**

10
11 A. No. Under utility ratemaking, expenses and revenues are constantly changing. The day
12 after a rate decision goes into effect, the utility will experience some expenses that
13 increase while other expenses decrease. So long as the utility is earning its allowed rate
14 of return, it is fully recovering all of the expenses that were recognized in its most recent
15 rate case. However, even if the utility is not earning its allowed rate of return, the
16 shortfall cannot be ascribed to any particular expense. There is no reason to conclude
17 that universal service expenses are the last expenses to be paid (and thus not fully
18 recovered) rather than the first expenses to be paid. To remove these staffing and call
19 center expenses from the Rider D does not mean, at all, that these expenses are not
20 subject to full recovery. They are instead simply recovered through base rates.

21 **Part 2. Universal Service Cost Offsets.**

22 **Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR**
23 **TESTIMONY.**

24
25 A. *In this section of my testimony, I outline the universal service cost offsets that are*
26 *necessary to fully implement the PUC's cost recovery principles. The PUC has*
27 *established principles that call for a utility to include in any proposed universal service*

1 cost recovery, as an offset to cost recovery, cost savings it incurred in cash working
2 capital, bad debt expense, and credit and collection costs.

3 **A. Bad Debt Offset Associated with Incremental CAP Costs.**

4 **Q. PLEASE EXPLAIN THE BAD DEBT OFFSET YOU PROPOSE TO THE**
5 **COMPANY'S CAP RATE COST RECOVERY.**

6
7 A. The bad debt offset is designed to prevent the utility from collecting costs that it will no
8 longer incur as it expands its universal service programs. Confirmed low-income
9 customers that are in arrears and not participating in the Company's CAP program will
10 impose a bad debt expense on the Company. The bad debt expense created by the arrears
11 of these confirmed low-income customers is reflected in the Company's base rates paid
12 by all residential customers. As the Company expands its CAP program, the revenues
13 represented by the CAP shortfall will no longer be billed to those confirmed low-income
14 customers. Since that revenue is no longer billed to these confirmed low-income
15 customers, but recovered through base rates to all customers, the bad debt expense
16 associated with those billings will no longer be incurred. As a result, the incremental
17 CAP shortfall should be reduced by an offset equal to the incremental revenues collected
18 through the CAP program multiplied by the bad debt rate for confirmed low-income
19 customers.

20 **Q. WHAT IS THE VALUE OF THE BAD DEBT OFFSET TO THE EQUITABLE**
21 **GAS CAP COST RECOVERY?**

22
23 A. The bad debt offset is equal to the incremental cost recovery sought by the Company
24 times the most recent bad debt rate for confirmed low-income customers. The most
25 recent bad debt rate reported by the PUC's Bureau of Consumer Services ("BCS") for the
26 confirmed low-income customers of Equitable Gas was 15.83%. The incremental cost

1 recovery I calculate above is \$7,715,537 (\$19,117,521 total universal service costs --
2 \$11,401,984 universal service costs in current rates = \$7,715,537). Multiplied by 15.83%
3 yields a bad debt offset of \$1,221,370 ($\$7,715,537 \times 0.1583 = \$1,221,370$).

4 **Q. DOES THIS BAD DEBT OFFSET INCLUDE THE COMPANY'S ARREARAGE**
5 **FORGIVENESS COST RECOVERY?**

6
7 A. Yes. Under the Company's arrearage forgiveness proposal, rather than continuing to bill
8 CAP participants for their preprogram arrears, the Company will forbear such billing and
9 instead grant arrearage forgiveness credits so long as the CAP participant makes the
10 required CAP payments. Accordingly, to the extent that the Company's proposed cost
11 recovery of \$780,397 for the forgiveness of pre-program arrears contributes to the
12 incremental cost recovery of \$7,715,537, it should also be reduced by the bad debt rate
13 for confirmed low-income customers.

14 **B. Working Capital Offsets Associated with Incremental CAP Costs.**

15 **Q. PLEASE EXPLAIN THE WORKING CAPITAL OFFSET YOU PROPOSE TO**
16 **THE COMPANY'S CAP RATE COST RECOVERY.**

17
18 A. *In this section of my testimony, I identify the working capital reductions associated with*
19 *the reduction in arrears leading to bad debt write-offs in the set-offs accompanying the*
20 *Company's CAP cost recovery.*

21 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

22 A. I outline above how and why the Company should reduce its cost recovery for its CAP
23 credits and arrearage forgiveness by 15.83% to reflect the reduced uncollectibles
24 generated by the CAP program. The PUC has indicated in both its existing and proposed
25 CAP regulations that a utility should reflect reductions in working capital in any CAP
26 cost recovery.

1 **Q. WHY WOULD THERE BE A REDUCTION IN WORKING CAPITAL?**

2 A. As I explain above, the reduction in uncollectibles occurs not because the Company
3 improves its collection rate, but rather because Equitable Gas would cease to bill these
4 amounts. With CAP credits, the Company ceases to bill the CAP participant a portion of
5 bills rendered for current usage and instead collects that amount from other customers.
6 With arrearage forgiveness, the Company ceases to bill the CAP participant for pre-
7 existing arrears and instead collects that amount from other customers.

8 **Q. AT WHAT POINT IN TIME DOES EQUITABLE WRITE-OFF AN**
9 **ARREARAGE AS UNCOLLECTIBLE?**

10
11 A. Equitable Gas deems a residential account to be uncollectible if the account remains
12 unpaid after the service is either discontinued at the customer's request or terminated and
13 two final bills are issued and are not paid.

14 **Q. HOW DO YOU CALCULATE AN AVOIDED WORKING CAPITAL EXPENSE?**

15 A. To calculate an avoided working capital expense, I use a two-step process. In Step 1, I
16 determine the expected age of the arrears prior to write-off. To do so, I determine the age
17 of a typical arrears for a confirmed low-income customer. Using the average arrears of
18 confirmed low-income customers, I find that these arrears represent five months of a
19 typical CAP Rate non-discounted bill. According to the most recent BCS universal
20 service report, the average arrears for a confirmed low-income customer for Equitable
21 Gas is \$402. Divided by a typical non-discounted monthly average bill of \$86, the
22 average age of arrears is five months ($\$402 / \$86 = 4.7$). In addition to this five month
23 age of the average arrears, I add the two month lag between the time an active account is
24 disconnected and the account is deemed to be uncollectible. The total lag, therefore, is

1 seven months (five months in arrears for an active account plus two months after a
2 disconnection occurs and a final bill is issued).

3 In Step 2, I apply a daily cost of capital to the lag I identify in the first step. In
4 calculating a multiplier in this fashion, there should be an additional 3.88% included to
5 account for the working capital associated with the Company's foregone write-off. The
6 calculation of this 3.88% is set forth in Schedule RDC-4. This offset should then be
7 applied to the marginal revenue identified in the Company's Rider D. The level of the
8 multiplier does not depend on the number of dollars to which the multiplier is applied.

9 **Q. WHAT IS THE VALUE OF THIS WORKING CAPITAL ADJUSTMENT?**

10 A. The working capital offset is equal to the incremental cost recovery sought by the
11 Company times the 3.88% offset rate calculated above. The incremental cost recovery
12 sought by the Company is \$7,715,537 (\$19,117,521 total universal service costs -
13 \$11,401,984 universal service costs in current rates = \$7,715,537). Multiplied by the
14 working capital adjustment that I calculate above (3.88%) results in a working capital
15 offset of \$299,363.

16 **Q. DOES THIS WORKING CAPITAL OFFSET ALSO APPLY TO THE**
17 **COMPANY'S ARREARAGE FORGIVENESS COST RECOVERY?**
18

19 A. Yes. Under the Company's arrearage forgiveness proposal, rather than continuing to bill
20 CAP participants for their preprogram arrears, the Company will forbear such billing and
21 grant arrearage forgiveness credits so long as the CAP participant makes the required
22 CAP payments. Accordingly, to the extent that the Company's proposed arrearage
23 forgiveness cost recovery contributes to the total increase in universal service costs, that
24 arrearage forgiveness should also be reduced by the working capital offset calculated
25 above.

1 **Q. IS THE APPLICATION OF A WORKING CAPITAL AND BAD DEBT**
2 **ADJUSTMENT TO ARREARAGE FORGIVENESS COST RECOVERY**
3 **CONSISTENT WITH PUC POLICY?**
4

5 A. Yes. In PUC's October 2006 final order with respect to the Commission's investigation
6 into CAP cost recovery, the PUC found:

7 Regarding arrearage forgiveness costs, it is not possible to make a definitive
8 ruling as to the entire amount of these costs. There is some merit in
9 reasoning that arrearage forgiveness amounts should not be recovered
10 separately because these are amounts that, but for the existence of the CAP
11 program, would be included within the utility's claim for uncollectible
12 expenses. The law requires "full recovery" of CAP costs, but not "double
13 recovery." At the same time, utilities should have the opportunity to
14 demonstrate when they seek to establish a surcharge that arrearage
15 forgiveness costs are not completely covered by uncollectible expenses. The
16 utilities should bear the burden of proving that allowing recovery of their
17 claim for arrearage forgiveness costs will not give them double-recovery of
18 these costs.
19

20 Final Investigatory Order, Customer Assistance Programs: Funding Levels and Cost
21 Recovery Mechanisms, Docket No. M-00051923, at 38 (October 19, 2006). Several
22 critical observations flow from this Commission order. First, the Commission
23 acknowledges that, at least for some portion of forgiven arrears, "these are amounts that,
24 but for the existence of the CAP program, would be included within the utility's claim for
25 uncollectible expenses." Second, while a utility is entitled to "full recovery," it is not
26 entitled to "double recovery." Finally, it is the Company that bears the burden of proving
27 that its cost recovery "will not give them double-recovery" of costs. While Equitable has
28 chosen to ignore this Commission directive, my proposal above is in full compliance with
29 this directive and gives the directive substance.

30 The Commission carries this policy forward into its currently pending proposed
31 CAP regulations (Universal Service and Energy Conservation Reporting Requirements
32 and Customer Assistance Programs, Docket No. L-00070186/57-257, 38 Pa. Bulletin 776

(February 9, 2008)). In its proposed regulations, the PUC provides that recoverable CAP Costs include "preprogram arrearage forgiveness to the extent that a distribution company can prove that recovery of these costs will not result in double recovery" (Proposed Rule §76.4(2)(iii)). Equitable, however, has made no such demonstration. Moreover, the Commission provides in its proposed regulations that "the company [seeking cost recovery] shall include, as an offset to cost recovery, cost savings it incurred in the following areas: (i) Cash working capital; [and] (ii) bad debt expense." Despite the mandatory "shall," Equitable has proposed no such offsets in this proceeding. The fact that these regulations are pending is inapposite to their applicability to Equitable. The pending regulations do not impose new requirements, but simply further implement the requirements first articulated by the Commission in its October 2006 Final Investigatory Order in Docket M-00051923.

G. Summary of Modifications to Universal Service Cost Recovery.

Q. CAN YOU SUMMARIZE AND CONSOLIDATE THE PROPOSED ADJUSTMENTS YOU MAKE TO THE COMPANY'S COST RECOVERY PROPOSAL?

A. Yes. Schedule RDC-5 presents a side-by-side comparison of my calculation of universal service costs (with cost offsets) to the universal service costs proposed by the Company in Attachment JM-Q-2. The Rider D cost recovery I propose for Equitable Gas is \$0.8951 per MCF.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, :
 :
 v. : Docket No. R-2008-2029325, et al
 :
 Equitable Gas Company :

Independent Oil and Gas Association of :
 Pennsylvania :
 v. : C-20066800
 Equitable Gas Company :

SCHEDULES AND
ATTACHMENT TO THE
DIRECT TESTIMONY OF
ROGER D. COLTON

§
ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

October 8, 2008

CORRECTED 10/14/08

Schedule RDC-1

Difference Between Equitable Gas Calculation of CAP Commodity Revenue and Colton Calculation of Commodity Revenue (2008)				
	Rates	Colton	Equitable /a/	Difference
Bills per year		204,885	227,712	
Consumption per bill		11.1	11.1	
Total consumption		2,274,224	2,528,051	
Commodity charge	\$2.523	\$5,737,866	\$6,378,273	
Rider C Transition charge	\$0.227	\$516,249	\$573,868	
Natural gas supply	\$13.970	\$31,770,902	\$35,316,872	
Balance Charge	\$0.180	\$409,360	\$455,049	
Total commodity charge		\$38,434,377	\$42,724,062	\$4,289,685
NOTES:				
/a/ JMQ-2.				

CORRECTED 10/14/08

Schedule RDC-2

Universal Service Costs to be Recovered Prior to Offsets (Colton)				
1	Service charge revenue	\$2,386,916		
2	Commodity charge revenue	\$38,434,377		
3	Total revenue (sum 1 + 2)	\$40,821,293		
4	Customer payments (No. of bills x payment per bill)	\$16,948,087	204,885 /a/	\$82.72 /b/
5	Total CAP shortfall (100%) (3 – 4)	\$23,873,206		
6	Actual shortfall payment rate	74%		
7	Actual shortfall payment amount (5 x 6) /c/	\$17,666,172		
8	Arrearage forgiveness	\$780,397		
9	LIURP	\$698,139		
10	Total Universal Service Costs (sum 7 + 8 + 9)	\$19,144,708		

NOTES:

/a/ Number of bills rendered to CAP customers.

/b/ Average payment per CAP bill rendered.

/c/ No STAS adjustment has been applied to this figure.

CORRECTED 10/14/08

Schedule RDC-3

Side by Side Comparison of Company's Universal Service Cost Proposal and Colton's Universal Service Cost Proposal
(without cost offsets)

	Company proposal (JMQ-2)	Colton proposal (consolidated adjustments)
Customer charge revenue	\$2,652,845	\$2,386,916
Commodity charge revenue	\$42,724,062	\$38,434,377
STAS	(\$40,839)	(\$36,739)
Total Rate RS	\$45,336,068	\$40,784,554
Customer payments (including LIHEAP)	\$18,837,122	\$16,948,087
CAP shortfall	\$26,498,946	\$23,836,467
Adjust for CAP credits not paid (74%)	\$26,498,946	\$17,638,985
CAP arrearage forgiveness	\$780,397	\$780,397
LIURP	\$698,139	\$698,139
CAP administrative costs	\$299,194	\$0
Total CAP/LIURP Costs to be recovered	\$28,276,676	\$19,117,521
Existing universal service funding	\$11,401,984	\$11,401,984
Increase in universal service funding	\$16,874,692	\$7,715,537
Bad debt offsets	\$0	\$0
Working capital offset	\$0	\$0
Total CAP/LIURP costs to be recovered (no offsets)	\$28,276,676	\$19,117,521
Normalized non-CAP residential throughput	19,658,593	19,658,593
Proposed Rider D Rate	\$1.4384	\$0.9725
Current funding	\$11,401,984	\$11,401,984
Increase in funding	\$16,874,692	\$7,715,537

CORRECTED 10/14/08

Schedule RDC-4

Working Capital on Avoided Bad Debt From CAP Credits and Arrearage Forgiveness (Equitable Gas) (2008)						
		Bills Behind				
	From Invoice Date to Bill Due Date	1	2	3	4	5
Arrears	\$1,000.00	\$200	\$200	\$200	\$200	\$200
Incremental age to disconnection (5 months total)	15	15	45	75	105	135
Age after disconnection (1 months total)		60	60	60	60	60
Dollar Lag Days	135,000	15,000	21,000	27,000	33,000	39,000
Annualized Weighted Return	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%
Gross Up Factor for Taxes	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Weighted Return (GUFT)	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%
Days per Year	365	365	365	365	365	365
Daily Return (GUFT)	0.0288%	0.0288%	0.0288%	0.0288%	0.0288%	0.0288%
Working Capital	\$38.84	\$4.32	\$6.04	\$7.77	\$9.49	\$11.22
Annualized Working Capital per \$1,000	\$38.84					
WC per \$1 of CAP credits	\$0.0388					
WC offset (percentage)	3.88%					

CORRECTED 10/14/08

Schedule RDC-5 (revised)

Side by Side Comparison of Company's Universal Service Cost Proposal and Colton's Universal Service Cost Proposal
(with cost offsets)

	Company proposal (JMQ-2)	Colton proposal (consolidated adjustments)
Customer charge revenue	\$2,652,845	\$2,386,916
Commodity charge revenue	\$42,724,062	\$38,434,377
STAS	(\$40,839)	(\$36,739)
Total Rate RS	\$45,336,068	\$40,784,554
Customer payments (including LIHEAP)	\$18,837,122	\$16,948,087
CAP shortfall	\$26,498,946	\$23,836,467
Adjust for CAP credits not paid (74%)	\$26,498,946	\$17,638,985
CAP arrearage forgiveness	\$780,397	\$780,397
LIURP	\$698,139	\$698,139
CAP administrative costs	\$299,194	\$0
Total CAP/LIURP Costs to be recovered	\$28,276,676	\$19,117,521
Existing universal service funding	\$11,401,984	\$11,401,984
Increase in universal service funding	\$16,874,692	\$7,715,537
Bad debt offsets (15.83%)	\$0	(\$1,221,370)
Working capital offset (3.88%)	\$0	(\$299,363)
Total CAP/LIURP costs to be recovered	\$28,276,676	\$17,596,789
Normalized non-CAP residential throughput	19,658,593	19,658,593
Proposed Rider D Rate	\$1.4384	\$0.8951
Current funding	\$11,401,984	\$11,401,984
Increase in funding	\$16,874,692	\$6,194,805

CORRECTED 10/14/08

Attachment RC-1

ROGER D. COLTON

BUSINESS ADDRESS:

Fisher Sheehan & Colton
Public Finance and General Economics
34 Warwick Road, Belmont, MA 02478
617-484-0597 (voice) *** 617-484-0594 (fax)
roger@fsconline.com (e-mail)
<http://www.fsconline.com> (www address)

EDUCATION:

J.D. (Order of the Coif), University of Florida (1981)

M.A. (Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975)

PROFESSIONAL EXPERIENCE:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 - present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including: regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than three dozen states. He is particularly noted for creative program design and implementation within tight budget constraints.

National Consumer Law Center (NCLC): 1986 - 1994

As a staff attorney with NCLC, Colton worked on low-income energy and utility issues. He pioneered cost-justifications for low-income affordable energy rates, as well as developing models to quantify the non-energy benefits (e.g., reduced credit and collection costs, reduced working capital) of low-income energy efficiency. He designed and implemented low-income affordable rate and fuel assistance programs across the country. Colton was charged with developing new practical and theoretical underpinnings for solutions to low-income energy problems.

Community Action Research Group (CARG): 1981 - 1985

As staff attorney for this non-profit research and consulting organization, Colton worked primarily on energy and utility issues. He provided legal representation to low-income persons on public utility issues; provided legal and technical assistance to consumer and labor organizations; and provided legal and technical assistance to a variety of state and local governments nationwide on natural gas, electric, and telecommunications issues. He routinely appeared as an expert witness before regulatory agencies and legislative committees regarding energy and telecommunications issues.

PROFESSIONAL AFFILIATIONS:

Member: Board of Directors, Belmont Housing Trust, Inc.
Member: Advisory Board: Fair Housing Center of Greater Boston.
Past Member: Fair Housing Committee, Town of Belmont (MA)
Past Member: Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member: Board of Directors, Vermont Energy Investment Corporation.
Past Member: Board of Directors, National Fuel Funds Network
Past Member: National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member: Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member: ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member: National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member: National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

PROFESSIONAL ASSOCIATIONS:

National Association of Housing and Redevelopment Officials (NAHRO)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)
International Society for Policy Studies
Association for Social Economics

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COLTON EXPERIENCE AS EXPERT WITNESS

1988 - PRESENT

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O Equitable Gas Company	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	08
I/M/O Columbia Gas Company	Witness	Office of Ohio Consumers' Counsel	Rate design	Ohio	08
I/M/O Dominion East Ohio Gas Company	Witness	Office of Ohio Consumers' Counsel	Rate design	Ohio	08
I/M/O Vectren Energy Delivery Company	Witness	Office of Ohio Consumers' Counsel	Rate design	Ohio	08
I/M/O Public Service Company of North Carolina	Witness	NC Department of Justice	Rate design	North Carolina	08
I/M/O Piedmont Natural Gas Company	Witness	NC Department of Justice	Rate design	North Carolina	08
I/M/O National Grid	Witness	New Hampshire Legal Assistance	Low-income rate assistance	New Hampshire	08
I/M/O EmPower Maryland	Witness	Office of Peoples Counsel	Low-income energy efficiency	Maryland	08
I/M/O Duke Energy Carolinas Save-a-Watt Program	Witness	NC Equal Justice Foundation	Low-income energy efficiency	North Carolina	08
I/M/O Zia Natural Gas Company	Witness	Community Action New Mexico	Low-income/low-use rate design	New Mexico	08
I/M/O Universal Service Fund Support for the Affordability of Local Rural Telecomm Service	Witness	Office of Consumer Advocate	Telecomm service affordability	Pennsylvania	08 - 09
I/M/O Philadelphia Water Department	Witness	Public Advocate	Credit and Collections	Philadelphia	08
I/M/O Portland General Electric Company	Witness	Community Action--Oregon	General rate case	Oregon	08
I/M/O Philadelphia Electric Company (electric)	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	08
I/M/O Philadelphia Electric Company (gas)	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	08
I/M/O Columbia Gas Company	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	08
I/M/O Public Service Company of New Mexico	Witness	Community Action New Mexico	Fuel adjustment clause	New Mexico	08
I/M/O Petition of Direct Energy for Low-Income Aggregation	Witness	Office of Peoples Counsel	Low-income electricity aggregation	Maryland	07
I/M/O Office of Consumer Advocate et al. v. Verizon and Verizon North	Witness	Office of Consumer Advocate	Lifeline telecommunications rates	Pennsylvania	07
I/M/O Pennsylvania Power Company	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	07
I/M/O National Fuel Gas Distribution Corporation	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	07
I/M/O Public Service of New Mexico--Electric	Witness	Community Action New Mexico	Low-income programs	New Mexico	07

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O Citizens Gas/NIPSCO/Vectren for Universal Service Program	Witness	Citizens Gas & Coke Utility/Northern Indiana Public Service/Vectren Energy	Low-income program design	Indiana	07
I/M/O PPL Electric	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	07
I/M/O Section 15 Challenge to NSPI Rates	Witness	Energy Affordability Coalition	Discrimination in utility regulation	Nova Scotia	07
I/M/O Philadelphia Gas Works	Witness	Office of Consumer Advocate	Low-income and residential collections	Pennsylvania	07
I/M/O Equitable Gas Company	Witness	Office of Consumer Advocate	Low-income program	Pennsylvania	07
I/M/O Section 11 Proceeding, Energy Restructuring	Witness	Office of Peoples Counsel	Low-income needs and responses	Maryland	06
I/M/O Citizens Gas/NIPSCO/Vectren for Universal Service Program	Witness	Citizens Gas & Coke Utility/Northern Indiana Public Service/Vectren Energy	Low-income program design	Indiana	06
I/M/O Public Service Co. of North Carolina	Witness	North Carolina Attorney General/Dept. of Justice	Low-income energy usage	North Carolina	06
I/M/O Electric Assistance Program	Witness	New Hampshire Legal Assistance	Electric low-income program design	New Hampshire	06
I/M/O Verizon Petition for Alternative Regulation	Witness	New Hampshire Legal Assistance	Basic local telephone service	New Hampshire	06
I/M/O Pennsylvania Electric Co./Metropolitan Edison Co.	Witness	Office of Consumer Advocate	Universal service cost recovery	Pennsylvania	06
I/M/O Duquesne Light Company	Witness	Office of Consumer Advocates	Universal service cost recovery	Pennsylvania	06
I/M/O Natural Gas DSM Planning	Witness	Low-Income Energy Network	Low-income DSM program.	Ontario	06
I/M/O Union Gas Co.	Witness	Action Centre for Tenants Ontario (ACTO)	Low-income program design	Ontario	06
I/M/O Public Service of New Mexico merchant plant	Witness	Community Action New Mexico	Low-income energy usage	New Mexico	06
I/M/O Customer Assistance Program design and cost recovery	Witness	Office of Consumer Advocate	Low-income program design	Pennsylvania	06
I/M/O NIPSCO Proposal to Extend Winter Warmth Program	Witness	Northern Indiana Public Service Company	Low-income energy program evaluation	Indiana	05
I/M/O Piedmont Natural Gas	Witness	North Carolina Attorney General/Dept. of Justice	Low-income energy usage	North Carolina	05
I/M/O PSEG merger with Exelon Corp.	Witness	Division of Ratepayer Advocate	Low-income issues	New Jersey	05
Re. Philadelphia Water Department	Witness	Public Advocate	Water collection factors	Philadelphia	05
I/M/O statewide natural gas universal service program	Witness	New Hampshire Legal Assistance	Universal service	New Hampshire	05
I/M/O Sub-metering requirements for residential rental properties	Witness	Tenants Advocacy Centre of Ontario	Sub-metering consumer protections	Ontario	05

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O National Fuel Gas Distribution Corp	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	05
I/M/O Nova Scotia Power, Inc.	Witness	Dalhousie Legal Aid Service	Universal service	Nova Scotia	04
I/M/O Lifeline Telephone Service	Witness	National Ass'n State Consumer Advocates (NASUCA)	Lifeline rate eligibility	FCC	04
Mackay v. Verizon North	Witness	Office of Consumer Advocate	Lifeline rates—vertical services	Pennsylvania	04
I/M/O Philadelphia Gas Works	Witness	Office of Consumer Advocate	Credit and collections	Pennsylvania	04
I/M/O Citizens Gas & Coke/Vectren	Witness	Citizens Action Coalition of Indiana	Universal service	Indiana	04
I/M/O PPL Electric Corporation	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	04
I/M/O Consumers New Jersey Water Company	Witness	Division of Ratepayer Advocate	Low-income water rate	New Jersey	04
I/M/O Washington Gas Light Company	Witness	Office of Peoples Counsel	Low-income gas rate	Maryland	04
I/M/O Washington Gas Light Company	Witness	Office of Peoples Counsel	Low-income gas rate	Maryland	03
Golden v. City of Columbus	Witness	Helen Golden	ECOA disparate impacts	Ohio	02
Huegel v. City of Easton	Witness	Phyllis Huegel	Credit and collection	Pennsylvania	02
I/M/O Universal Service Fund	Witness	Public Utility Commission staff	Universal service funding	New Hampshire	02
I/M/O Philadelphia Gas Works	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	02
I/M/O Washington Gas Light Company	Witness	Office of Peoples Counsel	Rate design	Maryland	02
I/M/O Consumers Illinois Water Company	Witness	Illinois Citizens Utility Board	Credit and collection	Illinois	02
I/M/O Public Service Electric & Gas Rates	Witness	Division of Ratepayer Advocate	Universal service	New Jersey	01
I/M/O Pennsylvania-American Water Company	Witness	Office of Consumer Advocate	Low-income rates and water conservation	Pennsylvania	01
I/M/O Louisville Gas & Electric Prepayment Meters	Witness	Kentucky Community Action Association	Low-income energy	Kentucky	01
I/M/O NICOR Budget Billing Plan Interest Charge	Witness	Cook County State's Attorney	Rate Design	Illinois	01
I/M/O Rules Re. Payment Plans for High Natural Gas Prices	Witness	Cook County State's Attorney	Budget Billing Plans	Illinois	01
I/M/O Philadelphia Water Department	Witness	Office of Public Advocate	Credit and collections	Philadelphia	01
I/M/O Missouri Gas Energy	Witness	Office of Peoples Counsel	Low-income rate relief	Missouri	01
I/M/O Bell Atlantic--New Jersey Alternative Regulation	Witness	Division of Ratepayer Advocate	Telecommunications universal service	New Jersey	01

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O T.W. Phillips Gas and Oil Co.	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O Peoples Natural Gas Company	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O UGI Gas Company	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O PFG Gas Company	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
Armstrong v. Gallia Metropolitan Housing Authority	Witness	Equal Justice Foundation	Public housing utility allowances	Ohio	00
I/M/O Bell Atlantic--New Jersey Alternative Regulation	Witness	Division of Ratepayer Advocate	Telecommunications universal service	New Jersey	00
I/M/O Universal Service Fund for Gas and Electric Utilities	Witness	Division of Ratepayer Advocate	Design and funding of low-income programs	New Jersey	00
I/M/O Consolidated Edison Merger with Northeast Utilities	Witness	Save Our Homes Organization	Merger impacts on low-income	New Hampshire	00
I/M/O UtiliCorp Merger with St. Joseph Light & Power	Witness	Missouri Dept. of Natural Resources	Merger impacts on low-income	Missouri	00
I/M/O UtiliCorp Merger with Empire District Electric	Witness	Missouri Dept. of Natural Resources	Merger impacts on low-income	Missouri	00
I/M/O PacifiCorp	Witness	The Opportunity Council	Low-income energy affordability	Washington	00
I/M/O Public Service Co. of Colorado	Witness	Colorado Energy Assistance Foundation	Natural gas rate design	Colorado	00
I/M/O Avista Energy Corp	Witness	Spokane Neighborhood Action Program	Low-income energy affordability	Washington	00
I/M/O TW Phillips Energy Co.	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O PECO Energy Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O National Fuel Gas Distribution Corp.	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O PFG Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O UGI Energy Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
Re. PSCO/NSP Merger	Witness	Colorado Energy Assistance Foundation	Merger impacts on low-income	Colorado	99 - 00
I/M/O Peoples Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
I/M/O Columbia Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
I/M/O PG Energy Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
I/M/O Equitable Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
Alleruzzo v. Klarchek	Witness	Barlow Alleruzzo	Mobile home fees and sales	Illinois	99
I/M/O Restructuring New Jersey's Natural Gas Industry	Witness	Division of Ratepayer Advocate	Universal service	Pennsylvania	99
I/M/O Bell Atlantic Local Competition	Witness	Public Utility Law Project	Lifeline telecommunications rates	New Jersey	99

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O Merger Application for SBC and Ameritech Ohio	Witness	Edgemont Neighborhood Association	Merger impacts on low-income consumers	Ohio	98 - 99
Davis v. American General Finnce	Witness	Thomas Davis	Damages in "loan flipping" case	Ohio	98 - 99
Griffin v. Associates Financial Service Corp.	Witness	Earlie Griffin	Damages in "loan flipping" case	Ohio	98 - 99
I/M/O Baltimore Gas and Electric Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
I/M/O Delmarva Power and Light Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
I/M/O Potomac Electric Power Co. Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
I/M/O Potomac Edison Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
VMHOA v. LaPierre	Witness	Vermont Mobile Home Owners Association	Mobile home tying	Vermont	98
Re. Restructuring Plan of Virginia Electric Power	Witness	VMH Energy Services, Inc.	Consumer protection/basic generation service	Virginia	98
Mackey v. Spring Lake Mobile Home Estates	Witness	Timothy Mackey	Mobile home fees	State ct. Illinois	98
Re. Restructuring Plan of Atlantic City Electric	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Re. Restructuring Plan of Jersey Central Power & Light	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Re. Restructuring Plan of Public Service Electric & Gas	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Re. Restructuring Plan of Rockland Electric	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Appleby v. Metropolitan Dade County Housing Agency	Witness	Legal Services of Greater Miami	HUD utility allowances	Fed. court: So. Florida	97 - 98
Re. Restructuring Plan of PECO Energy Company	Witness	Energy Coordinating Agency of Philadelphia	Universal service	Pennsylvania	97
Re. Atlantic City Electric Merger	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97
Re. IES Industries Merger	Witness	Iowa Community Action Association	Low-income issues	Iowa	97
Re. New Hampshire Electric Restructuring	Witness	NH Comm. Action Assn	Wires charge	New Hampshire	97
Re. Natural Gas Competition in Wisconsin	Witness	Wisconsin Community Action Association	Universal service	Wisconsin	96
Re. Baltimore Gas and Electric Merger	Witness	Maryland Office of Peoples Counsel	Low-income issues	Maryland	96
Re. Northern States Power Merger	Witness	Energy Cents Coalition	Low-income issues	Minnesota	96

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
Re. Public Service Co. of Colorado Merger	Witness	Colorado Energy Assistance Foundation	Low-income issues	Colorado	96
Re. Massachusetts Restructuring Regulations	Witness	Fisher, Sheehan & Colton	Low-income issues/energy efficiency	Massachusetts	96
Re. FERC Merger Guidelines	Witness	National Coalition of Low-Income Groups	Low-income interests in mergers	Washington D.C.	96
Re. Joseph Keliukuli III	Witness	Joseph Keliukuli III	Damages from lack of homestead	Honolulu	96
Re. Theresa Mahaulu	Witness	Theresa Mahaulu	Damages from lack of homestead	Honolulu	95
Re. Joseph Ching, Sr.	Witness	Re. Joseph Ching, Sr.	Damages from lack of homestead	Honolulu	95
Joseph Keaulana, Jr.	Witness	Joseph Keaulana, Jr.	Damages from lack of homestead	Honolulu	95
Re. Utility Allowances for Section 8 Housing	Witness	National Coalition of Low-Income Groups	Fair Market Rent Setting	Washington D.C.	95
Re. PGW Customer Service Tariff Revisions	Witness	Philadelphia Public Advocate	Credit and collection	Philadelphia	95
Re. Customer Responsibility Program	Witness	Philadelphia Public Advocate	Low-income rates	Philadelphia	95
Re. Houston Lighting and Power Co.	Witness	Gulf Coast Legal Services	Low-Income Rates	Texas	95
Re. Request for Modification of Winter Moratorium	Witness	Philadelphia Public Advocate	Credit and collection	Philadelphia	95
Re. Dept of Hawaii Homelands Trust Homestead Production	Witness	Native Hawaiian Legal Corporation	Prudence of trust management	Honolulu	94
Re. SNET Request for Modified Shutoff Procedures	Witness	Office of Consumer Counsel	Credit and collection	Connecticut	94
Re. Central Light and Power Co.	Witness	United Farm Workers	Low-income rates/DSM	Texas	94
Blackwell v. Philadelphia Electric Co.	Witness	Gloria Blackwell	Role of shutoff regulations	Penn. courts	94
U.S. West Request for Waiver of Rules	Witness	Wash. Util. & Transp. Comm'n Staff	Telecommunications regulation	Washington	94
Re. U.S. West Request for Full Toll Denial	Witness	Colorado Office of Consumer Counsel	Telecommunications regulation	Colorado	94
Washington Gas Light Company	Witness	Community Family Life Services	Low-income rates & energy efficiency	Washington D.C.	94
Clark v. Peterborough Electric Utility	Witness	Peterborough Community Legal Centre	Discrimination of tenant deposits	Ontario, Canada	94
Dorsey v. Housing Auth. of Baltimore	Witness	Baltimore Legal Aide	Public housing utility allowances	Federal district court	93
Penn Bell Telephone Co.	Witness	Penn. Utility Law Project	Low-income phone rates	Pennsylvania	93
Philadelphia Gas Works	Witness	Philadelphia Public Advocate	Low-income rates	Philadelphia	93
Central Maine Power Co.	Witness	Maine Assn Ind. Neighborhoods	Low-income rates	Maine	92
New England Telephone Company	Witness	Mass Attorney General	Low-income phone rates	Massachusetts	92
Philadelphia Gas Co.	Witness	Philadelphia Public Advocate	Low-income DSM	Philadelphia	92

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
Philadelphia Water Dept.	Witness	Philadelphia Public Advocate	Low-income rates	Philadelphia	92
Public Service Co. of Colorado	Witness	Land and Water Fund	Low-income DSM	Colorado	92
Sierra Pacific Power Co.	Witness	Washoe Legal Services	Low-income DSM	Nevada	92
Consumers Power Co.	Witness	Michigan Legal Services	Low-income rates	Michigan	92
Columbia Gas	Witness	Penn. State Office of Consumer Advocate (OCA)	Energy Assurance Program	Pennsylvania	91
Mass. Elec. Co.	Witness	Mass Elec Co.	Percentage of Income Plan	Massachusetts	91
AT&T	Witness	TURN	Inter-LATA competition	California	91
Generic Investigation into Uncollectibles	Witness	Penn OCA	Controlling uncollectibles	Pennsylvania	91
Union Heat Light & Power	Witness	Kentucky Legal Services (KLS)	Energy Assurance Program	Kentucky	90
Philadelphia Water	Witness	Philadelphia Public Advocate (PPA)	Controlling accounts receivable	Philadelphia	90
Philadelphia Gas Works	Witness	PPA	Controlling accounts receivable	Philadelphia	90
Mississippi Power Co.	Witness	Southeast Mississippi Legal Services Corp.	Formula ratemaking	Mississippi	90
Kentucky Power & Light	Witness	KLS	Energy Assurance Program	Kentucky	90
Philadelphia Electric Co.	Witness	PPA	Low-income rate program	Philadelphia	90
Montana Power Co.	Witness	Montana Ass'n of Human Res. Council Directors	Low-income rate proposals	Montana	90
Columbia Gas Co.	Witness	Penn. OCA	Energy Assurance Program	Pennsylvania	90
Philadelphia Gas Works	Witness	PPA	Energy Assurance Program	Philadelphia	89
Southwestern Bell Telephone Co.	Witness	SEMLSC	Formula ratemaking	Mississippi	90
Generic Investigation into Low-income Programs	Witness	Vermont State Department of Public Service	Low-income rate proposals	Vermont	89
Generic Investigation into Demand Side Management Measures	Consultant	Vermont DPS	Low-income conservation programs	Vermont	89
National Fuel Gas	Witness	Penn OCA	Low-income fuel funds	Pennsylvania	89
Montana Power Co.	Witness	Human Resource Develop. Council District XI	Low-income conservation	Montana	88
Washington Water Power Co.	Witness	Idaho Legal Service Corp.	Rate base, rate design, cost-allocations	Idaho	88

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

11/19/08
#B6. PA
R45

Pennsylvania Public Utility Commission,

v.

Equitable Gas Company

Docket No. R-2008-2029325, et al

Independent Oil and Gas Association of
Pennsylvania

v.

Equitable Gas Company

C-20066800

SURREBUTTAL TESTIMONY OF
ROGER D. COLTON

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

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SECRETARY'S BUREAU

NOVEMBER 14, 2008

1 **Q. PLEASE STATE YOUR NAME AND ADDRESS.**

2 A. My name is Roger Colton. My address is Fisher, Sheehan & Colton, Public Finance and
3 General Economics, 34 Warwick Road, Belmont, Massachusetts, 02478.

4 **Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY FILED**
5 **TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN**
6 **THIS PROCEEDING?**

7 A. Yes.

8 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

9 A. In my surrebuttal testimony, I will respond to the Rebuttal Testimony of John Quinn with
10 respect to the cost recovery through Rider D. Rider D is used to collect the costs of the
11 Company's Customer Assistance Program (CAP) and Low-Income Usage Reduction
12 Program (LIURP).

13 **Q. HOW IS YOUR SURREBUTTAL STRUCTURED?**

14 A. I address four issues in my surrebuttal testimony. First, I address the number of CAP bills
15 that the Company can reasonably be expected to issue per year. Second, I address the
16 Company's proposal regarding unclaimed CAP credits. Third, I address the offsets that
17 should be applied to the Company's CAP credit and arrearage forgiveness cost recovery.
18 Finally, I address the Company's proposal regarding administrative costs.

19 **Part 1. Number of CAP Bills.**

20 **Q. PLEASE COMMENT ON MR. QUINN'S DISCUSSION OF THE NUMBER OF**
21 **CAP PARTICIPANTS RECEIVING BILLS.**

22 A. In his rebuttal testimony, Mr. Quinn disputes my calculation of the number of bills the
23 Company's CAP recipients receive. The Company's calculation of the CAP shortfall to

1 **Q. DO YOU AGREE WITH MR. QUINN'S USE OF A 14.7% GROWTH RATE?**

2 A. No. Mr. Quinn does not indicate how he calculated a growth rate of 14.7% for 2007.
3 The only growth rate of 14.7% that I can calculate from the Company's database is the
4 growth in the number of CAP bills with current charges (January = 14,123; December =
5 16,202; $(16,202 - 14,123) / 14,123 = 0.147$). Using the growth rate in the number of
6 participant bills with current charges, however, would be an inappropriate growth rate to
7 use. The appropriate growth rate to use is the growth rate in the overall number of
8 participants.

9 **Q. WHY IS IT APPROPRIATE TO USE THE GROWTH RATE FOR THE TOTAL**
10 **NUMBER OF PARTICIPANTS RATHER THAN THE GROWTH RATE FOR**
11 **THE NUMBER OF PARTICIPANTS WITH CURRENT CHARGES?**

12 A. In the Equitable Gas program, CAP credits are almost exclusively granted only to CAP
13 participants with bills for current usage. Accordingly, in estimating the costs to be
14 recovered for the CAP program, one should look not at the total number of CAP
15 participants (some of whom do not receive CAP credits), but rather at the proportion of
16 total participants receiving bills for current usage. That proportion should stay reasonably
17 constant from year to year.

18 Multiple reasons exist as to why a customer may be a "CAP participant" and yet
19 not receive a CAP bill. As even Mr. Quinn acknowledges, one primary reason involves a
20 customer enrolling in the CAP program after his or her billing cycle for that month has
21 passed. If a customer enrolls in CAP on July 21, for example, but had already received
22 his or her monthly July bill on July 14, that customer appears in the database as a "CAP
23 participant" in July, but would not have received a CAP bill in July (and would thus

1 receive no CAP credit in July). To base cost recovery as if the customer had received a
2 CAP bill (and a CAP credit) would thus overstate CAP program costs.

3 There is no reason to believe that an increasing proportion of CAP participants are
4 enrolling at a time of the month that results in the issuance of a CAP bill with a CAP
5 credit. The number of CAP enrollees, and the rate at which customers enroll, is
6 determined by a number of factors, including the administrative resources available for
7 enrollment. Those resources do not provide for an increasing front-loading of enrollment
8 each month.

9 Accordingly, the growth rate to use in the number of bills should be the growth
10 rate in the total number of CAP participants. The total number of CAP participants in
11 January 2007 was 14,175. The total number of CAP participants in December 2007 was
12 16,210. The growth rate was thus 14% $([16,210 - 14,175] / 14,175 = 0.14)$.

13 **Q. PLEASE COMMENT ON MR. QUINN'S ESTIMATE OF 227,145 BILLS FOR**
14 **2008.**

15 A. Mr. Quinn testifies that the Company estimates it will issue 227,145 total CAP bills in
16 2008. (Equitable Statement 1-R, at 11). That figure is demonstrably over-stated. I reach
17 that conclusion based on two observations.

18 ➤ First, let me simply work with the Company's own numbers. Mr. Quinn states
19 that the Company projects a December 2008 CAP participation rate of 20,335.
20 (Equitable Statement 1-R, at 11). If I divide the Company's estimated total
21 number of bills (227,145) by the year-end participation rate reported by Mr.
22 Quinn (20,335 December 2008 CAP participants), I find that the Company
23 estimates rendering 11.2 CAP bills for each year-end CAP participant

(227,145 / 20,335 = 11.2). Since customers do not receive more than one CAP bill per month, what that figure tells us is that the Company's projected number of bills for the number of year-end participants assumes that each of the year-end participants was on the CAP program for 11 months or more. We know, however, that this result is over-stated. The total number of January (2008) CAP participants was 16,822; the total number of April (2008) participants was 18,535; the total number of July (2008) participants was 18,602. Given these participation rates, it is not possible for the Company to have issued 11.2 bills for each of the 20,335 CAP participants the Company projects to serve in December 2008.

➤ Second, the same result can be derived in a somewhat different fashion. Mr. Quinn estimates that the Company will render 227,145 CAP bills during 2008. Mr. Quinn reports that the December 2008 CAP participation rate is expected to be 20,335 customers. The database that the Company provided to OCA reports that the Company had 16,822 January 2008 participants (OCA-V-12). Taking the average monthly participation rate implicit within those two numbers of 18,579 participants per month $[(20,335 + 16,822) / 2 = 18,579]$, we find that the Company is projecting to render 12.2 bills to each participant on average $(227,145 \text{ total bills} / 18,579 \text{ average participants} = 12.2 \text{ bills per participant})$. That result, of course, cannot happen. Since no customer will receive more than one bill per month, the highest number of bills per customer could be 12.0 (assuming that all participants were on the CAP program for the entire year). We know, however, that as even the Company concedes, not all

1 CAP participants receive CAP bills in each month in which they are a
2 “participant.” Accordingly, the number of bills per participant should be less
3 than 12.0. Based on this analysis, the Company’s estimate of 227,145 bills is
4 clearly over-stated.

5 **Q. DO YOU HAVE ANY FURTHER COMMENTS ON MR. QUINN’S REBUTTAL**
6 **TESTIMONY REGARDING THE NUMBER OF BILLS?**

7 A. Yes. Mr. Quinn argues that the Company “projected a more accurate annual participation
8 rate for 2008 and therefore it should be accepted as the appropriate methodology.”
9 (Equitable Statement 1-R, at 12). In fact, the Company presents a figure for its projected
10 number of bills, but never articulates or documents the “methodology” that it used to
11 derive that figure. Mr. Quinn’s argument that the Company’s proposal should be
12 accepted as “the appropriate methodology” presents no “methodology” for the
13 Commission to accept or reject. The methodology that should be used to project the
14 number of CAP bills to be used as the basis for estimating CAP costs is as follows: (1)
15 begin with the average number of bills with charges for current usage in the immediately
16 preceding 12 months; and (2) escalate that number by the percentage increase in total
17 CAP participants in the immediately preceding year (see, OCA Statement No. 4
18 (corrected), at 9 - 10).

19 **Q. PLEASE RESPOND TO MR. QUINN’S COMMENTS REGARDING THE**
20 **ADJUSTMENT YOU MAKE FOR CAP PARTICIPANTS THAT DO NOT HAVE**
21 **CAP USAGE.**

22 A. Mr. Quinn’s rebuttal testimony concedes that there are CAP customers that have no usage
23 associated with their account. Mr. Quinn argues, however, that “[i]f a customer only uses

1 natural gas for space heating, it is possible that the customer would have no consumption
2 during the summer months. . .” (Equitable Statement 1-R, at 13). The customer who only
3 uses natural gas for space heating, and who thus has no consumption but nonetheless
4 makes summer payments, does not explain the phenomenon that I identify. While there
5 is a seasonality to the customers with no consumption, the no-usage customers do not fall
6 entirely within the non-heating season. In the database of CAP participants that the
7 Company provided in response to OCA-V-12, it is possible to identify those customers
8 with no consumption for each month of the year. According to that database, roughly
9 46% of the customers with no usage fall within the months of October through May, all
10 months that have heating usage associated with them.

11 **Q. WHAT DO YOU CONCLUDE?**

12 A. The explanation Mr. Quinn presents in his rebuttal testimony for why CAP participants
13 may have bills with no usage is not supported by the database of CAP participants
14 provided by the Company (OCA-V-12).

15 **Q. WHAT DO YOU RECOMMEND?**

16 A. The combined impact of the adjustment to the number of CAP bills is to reduce the CAP
17 credit by \$2,662,479 (\$26,498,946 Company estimate - \$23,836,467 OCA estimate =
18 \$2,662,479 adjustment). I recommend that the Company’s cost recovery be reduced by
19 this amount.
20

Part 2. UNCLAIMED CAP CREDITS.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR SURREBUTTAL TESTIMONY.

A. In this section of my surrebuttal testimony, I respond to the Rebuttal Testimony of John Quinn with respect to unclaimed CAP credits. Mr. Quinn concedes the essential components of the adjustment, which I explained in my Direct Testimony. He acknowledges that "CAP participants do not earn a CAP credit until they make their full required CAP payment." (Equitable Statement 1-R, at 15). He further acknowledges that "historical evidence supports the premise that CAP customers do not make 100% of their required CAP payments." (Equitable Statement 1-R, at 15).

Mr. Quinn does mis-analyze the extent of the difference. He appears to argue that the proportion of dollars that are paid (74%) plus the proportion of dollars that are written off as uncollectible (15.83%) should equal 100% of the total CAP billings. (Equitable Statement 1-R, at 15). This is not accurate. A customer may be in arrears without having that arrears be uncollectible. A customer receiving a bill in March with a \$100 arrears from his or her February bill would fall into neither the 74% payment category nor the 15.83% uncollectible category. Mr. Quinn's assertion that there is a "problem" because the payment rate (74%) plus the uncollectible rate (15.83%) do not add to 100% is in error.

Q. PLEASE COMMENT ON MR. QUINN'S PROPOSED RESPONSE TO YOUR ADJUSTMENT FOR UNCLAIMED CAP CREDITS.

A. Mr. Quinn testifies that "Equitable is willing to . . . provide CAP credits when a CAP customer's bill is rendered. . . On a going forward basis, Equitable would recognize CAP

1 credits when a CAP bill is issued. Therefore, each CAP bill rendered would generate a
2 CAP credit.” (Equitable Statement 1-R, at 16). The OCA would accept that proposal.
3 This proposal is consistent with the CAP structures of other Pennsylvania utilities.
4 Adopting this Company proposal would render my associated recommended adjustment
5 moot.

6 **Q. WHAT IS THE FINANCIAL IMPACT OF ACCEPTING THIS COMPANY**
7 **PROPOSAL?**

8 A. Accepting this Company proposal would add \$6,197,481 in CAP credits to the Rider D
9 cost recovery. Those additional CAP credits would be offset by \$981,061 in bad debt
10 offsets ($\$6,197,481 \times 15.83\% = \$981,061$) and by \$240,462 in working capital offsets
11 ($\$6,197,481 \times 3.88\% = \$240,462$). Accordingly, the net additional CAP cost recovery is
12 \$4,975,958 ($\$6,197,481 - \$981,061 - \$240,462 = \$4,975,958$).

13 **Part 3. CAP Offsets.**

14 **Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR**
15 **TESTIMONY.**

16 A. In my Direct Testimony, I recommend two offsets to CAP costs that need to be made for
17 the Company’s CAP cost recovery to be in compliance with the Commission’s cost
18 recovery guidelines. I recommended that the Company make adjustments based on a bad
19 debt offset as well as based on a working capital offset. Mr. Quinn’s Rebuttal Testimony
20 does not dispute the propriety of making such adjustments. Instead, he argues that the
21 Company has already reflected bad debt and working capital savings in rates. I will
22 explain below how Mr. Quinn’s testimony refers to a different adjustment than the one
23 that I recommend in my Direct Testimony.

1 **Q. PLEASE RESPOND TO MR. QUINN'S REBUTTAL TESTIMONY REGARDING**
2 **YOUR PROPOSED BAD DEBT ADJUSTMENT.**

3 A. Mr. Quinn claims that the Company has already taken the reduced bad debt generated by
4 the Company's CAP program into account in presenting its revenue requirement for this
5 rate case. He cites to a reduction in bad debt expense of \$1,162,312 from prior year bad
6 debt expense "in part due to the expansion of the CAP program." (Equitable Statement 1-
7 R, at 19).

8 Mr. Quinn is correct that the Company's bad debt expenses for confirmed low-
9 income customers appear to be decreasing. This reduction may well, in fact, be
10 reasonably attributable to the expansion of the Company's CAP program. The
11 percentage of revenue written off as bad debt by Equitable was 18.27% in 2006, but only
12 15.83% in 2007. The dollar value of arrears for confirmed low-income customers was
13 \$5,253,193 in 2006, but only \$4,410,631 in 2007. (Bureau of Consumer Services,
14 Universal Service Reports, annual). The percentage of the Company's confirmed low-
15 income customers in debt was 17% in 2006, but only 14% in 2007. Clearly, the
16 Company is improving its collection performance for confirmed low-income customers.
17 Accordingly, the Company's adjustment for a reduction in net write-offs may reasonably
18 be attributed to an expansion of the Company's CAP program.

19 These reduced write-offs due to improved payment patterns associated with CAP,
20 however, reflect a different adjustment than the adjustment I proposed. I noted the
21 distinction in my Direct Testimony, when I stated: "the reduction in uncollectibles occurs
22 not because the Company improves its collection rate." (OCA Statement No. 4
23 (corrected), at 29). That reduction (due to improved collections) is what Mr. Quinn

1 references (and what the Company has already incorporated into its test year pro forma
2 adjustments).

3 **Q. HOW DO YOU KNOW THAT THE COMPANY'S REDUCED**
4 **UNCOLLECTIBLES DOES NOT INCORPORATE THE CAP BAD DEBT**
5 **OFFSET YOU PROPOSE?**

6 A. The Company provided the workpapers underlying its bad debt adjustment in response to
7 OCA discovery. (OCA-IV-19). Those workpapers document the \$1,162,312 reduction in
8 bad debt expense Mr. Quinn references. One thing that Mr. Quinn did not note in his
9 rebuttal testimony was that the \$1,162,312 reduction includes the reduction in industrial
10 and commercial bad debt expense as well as the reduction in residential expenses. Even
11 apart from that, however, the \$1,162,312 bad debt adjustment that Mr. Quinn references
12 does not relate to the adjustment I recommend. Mr. Quinn's adjustment is based on the
13 fact that the Company's "per books" bad debt expense was \$8,559,290, while its actual
14 two-year average bad debt expense was only \$7,396,978, a difference of \$1,162,312.
15 (OCA-IV-19(b)). That adjustment is completely unrelated to the recommended offset I
16 made in my Direct Testimony.

17 **Q. CAN YOU SUMMARIZE THE DISTINCTION BETWEEN THE**
18 **UNCOLLECTIBLE ADJUSTMENT MR. QUINN DISCUSSES AND THE**
19 **UNCOLLECTIBLE OFFSET YOU RECOMMEND IN YOUR DIRECT**
20 **TESTIMONY?**

21 A. Yes. The implementation of a CAP program will have two impacts on uncollectibles for
22 a Pennsylvania utility such as Equitable. The first impact involves a reduction in the
23 dollars that are written off by the utility. Because customer payment patterns improve

1 under a CAP, the dollars of arrears and the dollars of write-offs are reduced. That
2 improvement in payment patterns, and the resulting reduction in arrears and
3 uncollectibles are reflected in the BCS data I cite above. It is this reduction in
4 uncollectibles due to improved payment patterns that the Company has incorporated into
5 its proposed rates as cited by Mr. Quinn.

6 The second impact arises because the Company will cease to bill a certain
7 proportion of the dollars that would have been billed to CAP customers in the absence of
8 the CAP program. For example, if without the CAP, the Company would have billed
9 \$1,000 to CAP participants with an uncollectible rate of 10%, the Company would
10 experience \$100 in uncollectibles ($\$1,000 \times 10\% = \$100$). However, if the Company bills
11 only \$750 to those same CAP participants under the program, the Company will
12 experience only \$75 in uncollectibles ($\$750 \times 10\% = \$75$). This is the impact that the
13 Company has failed to incorporate into its proposed rates. As you can see, this second
14 impact is independent of whether the payment patterns improve or not.

15 In sum, the uncollectibles adjustment referenced in the Company's pro forma
16 adjustments filed in this rate case are different from the adjustment that I recommend.
17 The adjustment I propose is attributable to the fact that the Company ceases to bill CAP
18 customers for the dollars represented by its CAP credits. The Company's cost recovery
19 for CAP credits should be reduced by a bad debt offset.

20 **Q. DOES THE SAME RATIONALE APPLY TO WORKING CAPITAL?**

21 A. Yes. As with his discussion of bad debt, Mr. Quinn's discussion of working capital is
22 applicable to the reduction in arrears (and thus the reduction in working capital) caused
23 by the improved payment patterns I identify above. It does not apply to the working

1 capital associated with the reduced bad debt that I explain above. The working capital
2 offset I calculate is based on the recognition that the Company ceases to bill the dollars
3 represented by the CAP credits.

4 **Q. DO YOUR OFFSETS APPLY EQUALLY TO ARREARAGE FORGIVENESS?**

5 A. Yes. For all of the reasons I explain in my Direct Testimony, the offsets apply equally to
6 arrearage forgiveness.

7 **Part 4. CAP Administrative Costs.**

8 **Q. PLEASE RESPOND TO MR. QUINN'S REBUTTAL TESTIMONY REGARDING**
9 **ADMINISTRATIVE COSTS.**

10 A. In my Direct Testimony, I recommend that the Commission disallow the Company's
11 claim for \$299,194 in CAP administrative costs from collection through the Rider D. I
12 recommend instead that these administrative costs be collected through base rates. In
13 response, Mr. Quinn testifies that the Company has not historically spent \$299,194 on
14 CAP administrative costs. He proposes to reduce the Company's claim for cost recovery
15 for administrative costs from \$299,194 to \$168,794, a reduction of \$130,390. (Equitable
16 Statement 1-R, at 9). He states that he is "suggesting that [Colton's] adjustment be
17 revised to equal the Company's reduction of costs totaling \$130,390." (Equitable
18 Statement 1-R, at 9). The OCA accepts this Company proposal with respect to an
19 adjustment in the CAP administrative costs, to be collected in base rates, not through
20 Rider D.

1 **Q. HAVE YOU ATTACHED A REVISED SCHEDULE SETTING FORTH THE**
2 **CHANGES CONTAINED IN YOUR SURREBUTTAL TESTIMONY?**

3 A. Yes. Schedule RDC-2SR captures the revisions that OCA has accepted with respect to
4 the CAP cost recovery. Schedule RDC-2SR accepts the Company's proposal regarding
5 administrative costs. The Schedule further reflects the OCA's acceptance of Mr. Quinn's
6 proposal for the Company to reflect CAP credits at the time a CAP bill is issued. Given
7 the OCA's acceptance of these two proposals, Schedule RDC-2SR replaces and
8 substitutes for schedule RDC-5 (revised) attached to my Direct Testimony.

9 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

10 A. Yes it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	:	
	:	
v.	:	Docket No. R-2008-2029325, et al
	:	
Equitable Gas Company	:	
	:	
Independent Oil and Gas Association of	:	
Pennsylvania	:	
v.	:	C-20066800
Equitable Gas Company	:	

SCHEDULES TO THE
SURREBUTTAL TESTIMONY OF
ROGER D. COLTON

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

NOVEMBER 14, 2008

Schedule RDC-1SR

CAP Participants by Bill Attributes (2007) (Equitable Gas)			
2007 Months	Total CAP "Participants"	CAP Bills with Current Charges	CAP Bills with Usage
January	14,175	14,123	14,094
February	14,349	14,301	14,275
March	15,115	15,090	15,056
April	15,586	15,551	15,510
May	15,710	15,670	15,609
June	15,532	15,516	14,395
July	15,224	15,182	14,979
August	15,183	15,148	14,953
September	15,143	15,101	14,933
October	15,088	15,059	14,975
November	15,592	15,567	15,505
December	16,210	16,202	16,158
Annual total	182,907	182,510	180,442
Monthly average (annual total / 12)	15,242	15,209	15,036
SOURCE: OCA-V-12.			

Schedule RDC-2SR

	Company revised proposal	Colton's revised proposal
Customer charge revenue	\$2,652,845	\$2,386,916
Commodity charge revenue	\$42,724,062	\$38,434,377
STAS	(\$40,839)	(\$36,739)
Total Rate RS	\$45,336,068	\$40,784,554
Customer payments (including LIHEAP)	\$18,837,122	\$16,948,087
CAP shortfall	\$26,498,946	\$23,836,467
Adjust for CAP credits not paid (100%)	\$26,498,946	\$23,836,467
CAP arrearage forgiveness	\$780,397	\$780,397
LIURP	\$698,139	\$698,139
CAP administrative costs	\$168,794	\$0
Total CAP/LIURP Costs to be recovered	\$28,146,276	\$25,315,003
Existing funding	\$11,401,984	\$11,401,984
Incremental CAP/LIURP costs to be recovered	\$16,744,292	\$13,913,019
Bad debt offsets (15.83% of incremental costs)	\$0	(\$2,202,431)
Working capital offsets (3.88% of incremental costs)	\$0	(\$539,825)
Total costs to be recovered after offsets	\$28,146,276	\$22,572,747
Normalized non-CAP residential throughput	19,658,593	19,658,593
Proposed Rider D Rate (total costs / normalized throughput)	\$1.4318	\$1.1482
Current funding	\$11,401,984	\$11,401,984
Increase in funding	\$16,744,292	\$11,170,763