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BEFORE THE ARIZONA CORPORATION COMMISSION RECEIVED

CARL J. KUNASEK
CHAIRMAN
JIM IRVIN
COMMISSIONER
WILLIAM A. MUNDELL
COMMISSIONER

2000 NOV 22 A 11: 38

AZ CORP COMMISSION
DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, AND BLACK MOUNTAIN GAS, A SUBSIDIARY OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, TO DETERMINE EARNINGS FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN FOR THE CAVE CREEK DIVISION.

DOCKET NO. G-03703A-00-0283

STAFF'S NOTICE OF FILING DIRECT TESTIMONY

The Arizona Corporation Commission Staff ("Staff"), hereby files the Direct Testimony of Crystal S. Brown, Joel M. Reiker, Robert G. Gray and Marlin Scott, Jr., in the above-captioned matter

RESPECTFULLY SUBMITTED this 22nd day of November, 2000.

Arizona Corporation Commission
DOCKETED
NOV 22 2000
DOCKETED BY CQ

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Original and ten copies of the foregoing were filed this 22nd day of November, 29000 with:

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BEFORE THE ARIZONA CORPORATION COMMISSION RECEIVED

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AZ CORP COMMISSION
DOCUMENT CONTROL

CARL J. KUNASEK
Commissioner - Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, AND BLACK MOUNTAIN GAS, A SUBSIDIARY OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, TO DETERMINE EARNINGS FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN FOR THE CAVE CREEK DIVISION	DOCKET NO. G-03703A-00-0283

DIRECT

TESTIMONY

OF

CRYSTAL S. BROWN

RATE ANALYST II

UTILITIES DIVISION

NOVEMBER 2000

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SCHEDULES

SUMMARY OF DIRECT TESTIMONY
OF CRYSTAL BROWN
BLACK MOUNTAIN GAS COMPANY
DOCKET NO. G-03703A-00-0283
NOVEMBER, 2000

I will appear on behalf of the Arizona Corporation Commission Staff and will testify concerning Staff's position and recommendations regarding Black Mountain Gas Company's application for a permanent rate increase in the areas of original cost rate base, Test Year income statement adjustments, revenue requirements, operating income, and rate design. A summary of the significant recommendations that I will testify concerning are listed below:

1. Original Cost Rate Base – Staff proposes total rate base of $10,594,827.

2. Total Revenue Requirement – Staff proposes a total revenue requirement of $5,457,687.

3. Test Year Expenses – Staff proposes total Test Year expenses of $4,439,524.

4. Operating Income – Staff proposes an operating income of $1,018,163.

5. Rate Design – Staff began its rate design by setting the minimum charges for all classes equal to the minimum charges proposed by the Company. However, these charges generated less revenue than that which Staff had recommended for its revenue requirement. Consequently, Staff added $0.08804 to the present rate for all classes (except the compressed natural gas class) to generate the remainder of the revenue.

6. Other Issue – Staff recommends that the Company file an affidavit within 60 days of the date of the Decision resulting from this proceeding. The affidavit should assert the Company's compliance with Decision No. 58624, dated May 2, 1994 which ordered the Company to use its average short-term debt and average construction work in progress balances in the the FERC calculation.

EXECUTIVE SUMMARY

Proposed Revenue, Rate Base, and Operating Income

Q. Have you summarized Staff's and the Company's proposed revenue, rate base, and operating income?

A. Yes. I have summarized Staff's and the Company's proposed revenue, rate base, and operating income in the table below. I have also presented summary schedules for proposed revenue, rate base, and operating income with explanations to all of Staff's adjustments on Schedules 1 through 3.

	Company Proposed	Difference	Staff Proposed
Revenue	$6,103,325	($645,638)	$5,457,687
Rate Base	$11,100,500	($505,673)	$10,594,827
Oper Income	$871,566	(311,911)	$559,655

Proposed Rates and Charges

Q. Have you summarized Staff's and the Company's proposed rates and charges?

A. Yes. I have summarized Staff's and the Company's proposed rates and charges in the table below. I have also presented summary schedules for proposed rates and charges on Schedules 4 and 5.

	Company Proposed Residential	Difference	Staff Proposed Residential
Monthly Charge	$6.00	($0)	$6.00
Per Therm	$1.07940	($0.12116)	$0.95824

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Major Adjustments

Q. Would you please state the major adjustments that you have proposed that are different from the Company's?

A. The major adjustments Staff has proposed for rate base and income statement that are different than the Company's are discussed below.

Rate Base – Staff decreased rate base by $497,442 primarily due to removing $282,000 in Construction Work In Progress that had not been placed into service by Staff's cut off date.

Income Statement – Staff decreased operating income by $311,911. Staff removed $783,736 in proposed increase to the base cost of gas from present rate test year revenue. Staff also removed $236,128 from the purchased gas cost from operating expenses.

INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Crystal S. Brown. My business address is 1200 West Washington, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission ("Commission") as a Rate Analyst II.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Arizona with a Bachelor of Science Degree in Business Administration and from Arizona State University with a Bachelor of Science Degree in Accounting.

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I am a certified internal auditor and have attended numerous seminars related to auditing. After joining the Commission, I have participated in various regulatory training seminars.

These auditing and regulatory seminars have been sponsored by organizations such as the Center for Public Utilities, the National Association of Regulatory Utility Commissioners, Utilitech, Inc., the Arizona Corporation Commission, the Internal Revenue Service, the Department of Revenue, the Institute of Certified Internal Auditors, the Association of Government Accountants, the Office of the Auditor General, and the Association of Certified Fraud Examiners.

Prior to joining the Commission in August 1996, I was employed by the Department of Revenue as a Senior Internal Auditor and by the Office of the Auditor General as a Financial Auditor. I was a Cost Center Review Specialist for Blue Cross Blue Shield of Arizona prior to my employment in state government.

Q. Please describe your duties and responsibilities as a Rate Analyst II.

A. I am responsible for the examination and verification of utility financial systems in conjunction with rate applications. In addition, I analyze data for ratemaking purposes, evaluate the utility's current rate structure, propose rates and charges based on information analyzed during my regulatory audit and prepare written testimony and schedules, which include recommendations to the Commission. I am also responsible for testifying at formal hearings as it relates to the previously mentioned matters.

Q. What is the purpose of your testimony in this proceeding?

A. I am presenting Staff's analysis and recommendations concerning the original cost rate base ("OCRB"), Test Year income statement adjustments, revenue requirements and rate design regarding the Cave Creek operations of the Black Mountain Gas Division of Northern States Power Company ("Cave Creek" or "BMG" or "Company") rate increase application. Robert Gray will testify concerning Staff's recommended base cost of gas. Joel Reiker will testify concerning Staff's cost of capital recommendations. Marlin Scott will testify concerning Staff's cost of service study.

Q. Was this testimony prepared by you or under your direction?

A. Yes, it was.

Q. What is the basis of your recommendations?

I performed a regulatory audit of the Company's records to determine whether sufficient, relevant and reliable evidence exists to support BMG's assertions in its rate application. The regulatory audit consisted of an inspection of some of BMG's plant and facilities, examination and testing of selected amounts in the general ledger, tracing recorded amounts to supporting subsidiary ledgers and to source documentation, and verifying that the accounting principles applied were in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts for gas companies mandated by Commission Rules.

BACKGROUND

Q. Please review the pertinent background information associated with this application.

A. On April 28, 2000, Black Mountain Gas filed an application for a permanent rate increase for its Cave Creek Division. On May 26, 2000, Staff filed the sufficiency letter. On May 26, 2000, the Residential Utility Consumer Office ("RUCO") filed a motion to intervene.

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Northern States Power Company ("NSP") is a Minnesota corporation and a public utility that provides electric service at retail and wholesale in the states of Minnesota, North Dakota and South Dakota; and natural gas service at retail in the states of Minnesota and North Dakota. At year-end 1999, NSP had combined assets of $9.8 billion, with annual revenues of $3.4 billion.

In July 1998, NSP merged with Black Mountain Gas Company of Arizona through a stock-for-stock transaction approved in Decision No. 61009, dated July 16, 1998. NSP thus became an Arizona public utility providing natural gas and propane service subject to the jurisdiction of the Commission, doing business as ("d/b/a") Black Mountain Gas Company. In 1998, the total natural gas revenues and net utility assets of NSP d/b/a BMG in Arizona were approximately $6.7 million and $10.8 million, respectively.

In January 1999, NSP filed an application to transfer its natural gas and propane operations in Arizona to a new wholly owned subsidiary of NSP, i.e., BMG. Upon completion of the transfer, BMG became a wholly owned subsidiary of NSP, with its own capital structure, rates, and tariffs; and NSP became the holding company parent of BMG.

The Commission approved the transfer to BMG in Decision No. 61914, dated August 27, 1999.

In September, NSP and BMG filed a Notice of Restructure of Holding Company ("Merger Petition"), requesting Commission approval of the proposed merger of NSP and New Century Energies, Inc. ("NCE"), which would result in Xcel Energy Inc. ("Xcel") replacing NSP as the holding company parent of BMG.

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The Commission approved the proposed restructuring in Decision No. 62341, dated March 6, 2000. The Xcel merger is pending final regulatory approvals, including the Securities Exchange Commission ("SEC"). NSP expects the merger with NCE to close in the second quarter of 2000.

BMG's certificated service areas in Arizona are located in portions of the counties of Maricopa and Coconino. BMG is headquartered in Cave Creek, Arizona. It provides natural gas service to approximately 5,850 customers located in Cave Creek for residential, commercial, and other miscellaneous uses.

BMG's current rates were authorized approximately twelve years ago in Decision No. 55970, dated May 5, 1988. The order authorized an 8.05 percent rate of return on a $1,538,612 fair value rate base resulting in an increase of $62,243 (or 6.5 percent) in BMG's gross annual revenues.

Q. What Test Year was used by the Company in this filing?

A. BMG used a historical Test Year of the twelve months ended December 31, 1999.

SUMMARY OF PROPOSED REVENUES

Q. Please summarize the Company's proposal.

A. Please refer to Schedule 1, Pages 1 and 3, of my testimony. The Company is proposing total annual revenues of $6,103,325. This $6,103,325 represents an increase of $1,159,386 or 23.45 percent over the Company-filed annualized Test Year revenue of $4,943,939. (The $4,943,939 does not include the Company's proposal to increase Test Year present rate revenue by $783,736 to reflect the Company's projected increase in the cost of gas nor does it include $49,472 in net fuel adjustor revenues. Staff believes that these types of adjustments are inappropriate and should not be made to Test Year present rate revenue as discussed later in the "Revenue Adjustment" section of my testimony).

The Company filed annualized Test Year revenue of $5,777,147 includes $783,736 to reflect a pro-forma increase in its base cost of gas and $49,472 in net fuel adjustor revenue (as shown on Schedule 1, Page 2 of 5, Adjustments A and E). Without the base cost of gas increase and fuel adjustor revenue, BMG's annualized Test Year revenue is $4,943,939 (i.e. $5,777,147 - $783,736 - $49,472). As shown on Schedule 1, Page 3 of 5, this results in a Company proposed increase of $1,159,386 (i.e. $6,103,325 – $4,943,939) or 23.45 percent over Staff's adjusted annualized Test Year revenue.

Q. Please summarize Staff's proposal.

A. Please refer to Schedule 1, Pages 1 and 3, of my testimony. Staff is proposing total annual gross revenues of $5,457,687. This represents an increase of $513,748 or 10.39 percent over the Company annualized Test Year revenue of $4,943,939.

ORIGINAL COST RATE BASE ("OCRB")

Q. Has the Company prepared a Schedule showing the elements of Reconstruction Cost New Rate Base Net of Depreciation ("RCND")?

A. The Company's RCND Schedule is the same as its OCRB Schedule. The Company has requested a waiver of the development of RCND rate base. Therefore, Staff will evaluate BMG's application using the original cost rate base information it has provided.

Q. Have you prepared a schedule detailing the components and amounts representing the Company's proposed and Staff's adjusted OCRB?

A. Yes. Please refer to Schedule 2, Page 1 of 5. Staff has decreased original cost rate base by a net of $497,442, from $11,100,500 to $10,594,827.

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Post Test Year Plant

Q. What post-test year plant has the Company proposed to include in rate base?

A. The Company has proposed to include $502,044 for the purchase of a parcel of land with a building, $197,000 for the associated remodeling costs of the building, and $282,000 in services and mains construction projects. These plant assets will not be used and useful until after the Test Year ended December 31, 1999.

Q. What has Staff recommended concerning the $502,044 for the purchase of the parcel of land with a building, and the associated $197,000 for the remodeling costs of the building for this proceeding?

A. Staff recognizes that post-test year plant has historically been excluded from rate base because it fails the used and useful test. However, when a major construction project will be in service in the near future, it is not unusual for regulators to evaluate the merits of inclusion of post-test year plant in rate base on a case-by-case basis. In the case of BMG, Staff Engineering has determined that the land, building, and associated remodeling costs should be included in rate base.

Staff did not consider any related post-test year revenue or expenses as the cost of the land, building and remodeling are considered to have no effect on the revenue of BMG.

Concerning whether or not the $282,000 in post test-year construction projects were to be included in rate base, Staff used a cut-off date of August 31, 2000, for which the construction projects would have to be completed, placed in service, and the total cost of the projects would have to be removed from the CWIP account and transferred into the appropriate plant accounts.

This cut off date would allow Staff adequate time to audit and analyze the total cost of the plant assets. Staff reviewed the Company's general ledger CWIP account (printed

September 21, 2000) and determined that none of the $282,000 in construction projects had been removed from the CWIP account and transferred into the appropriate plant accounts by August 31, 2000. Therefore, Staff removed the Company proposed $282,000 in CWIP from rate base. If Staff included in rate base the construction projects that were completed after the Test Year, proper matching would require the addition of revenues and expenses generated from the use of those construction projects.

<u>Matters of Concern</u>

Q. Did any matters come to your attention while performing your audit?

A. Yes. During the audit, Staff noted the following: the last rate case of the Cave Creek Division of BMG was over 12 years ago; the Company had a large turnover in its accounting staff during the Test Year; the Company had a significant number of errors in its Test Year financial reports (that the Company has stated were later corrected); the Company was unable to produce documentation to support some of its plant; and the Company had converted its accounting system to a new system during the Test Year.

<u>Detail of Utility Plant</u>

Q. Please summarize your adjustments to the "Detail of Utility Plant" contained on Schedule 2, Page 2 of 5.

A. My adjustments to plant resulted in a net decrease of $111,610, from $15,745,435 to $15,633,825.

<u>Intangible Plant - Organization</u>

Q. Did you make any adjustments to account number 3010, Intangible Plant - Organization?

A. Yes. Please refer to Schedule 2, Page 3 of 5. Staff decreased the Intangible Plant - Organization account by $613,116, from $628,562 to $15,446. Staff reclassified $613,116 in order to remove costs that did not pertain to the organization of Black Mountain Gas as defined by the FERC UsoA.

The $355,648 was a cash payment BMG made to Southwest Gas Corporation ("Southwest Gas") pursuant to an agreement dated August 31, 1995. The agreement provided that Southwest Gas would build an additional delivery point from Southwest Gas to BMG for natural gas service to certain areas within BMG's service territory. The contract further specified that a portion of the advance was refundable and a portion was nonrefundable.

The refundable portion including gross up tax was to be repaid via a credit on BMG's gas bills from Southwest Gas annually over a period of five years.

The $355,648 cash advance payment was an expense BMG had incurred for an asset it had constructed in order to provide service for its ratepayers. Since BMG could not take title to or possession of the asset, the asset was an intangible plant asset. The expense was not incurred for the organization of the Company. Therefore, Staff removed the $355,648 from the Intangible Plant - Organization account and reclassified it as miscellaneous intangible plant. Accordingly, Staff removed $257,468 in advances related to a different contract that were recorded in the Intangible Plant - Organization account and reclassified the amount as miscellaneous intangible plant.

Allowance for Funds Used During Construction ("AFUDC")

Q. Did any matters come to your attention while auditing the Company's Allowance for Funds Used During Construction ("AFUDC") costs?

A. Yes. Decision No. 58624, dated May 2, 1994, ordered BMG to " . . . accrue an allowance for funds used during construction in accordance with the formula as specified in the Federal Energy Regulatory Commission's Order 561, for construction projects where debt and equity are used". Staff recommended the FERC calculation because it more

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closely approximated the Company's overall cost of capital. During the instant case, Staff noted that the Company was not in compliance with the FERC Order 561 formula for computing AFUDC rates.

Specifically, the Company did not incorporate into its formula average short-term debt and average construction work in progress as required by the FERC. Staff noted that for the Test Year, the Company had short-term debt and CWIP balances.

This noncompliance resulted in a higher AFUDC equity rate and, consequently, higher AFUDC equity amounts calculated, recorded and capitalized.

Q. What is Staff recommending concerning the non-compliance with Decision No. 58624, dated May 2, 1994?

A. Staff recommends that the Company file an affidavit within 60 days of the date of the Decision resulting from this proceeding. The affidavit should assert the Company's compliance with Decision No. 58624, dated May 2, 1994, which ordered the Company to use its average short-term debt and average construction work in progress balances in the FERC calculation.

Q. Did Staff have any other concerns about the Company's AFUDC accounts?

A. Yes. The FERC requires that the AFUDC calculated for a plant asset be included in the cost of the plant asset. Gas Plant Instruction No. 3 A, Components of construction cost, states, "The cost of construction properly includable in the gas plant accounts shall include, where applicable, the direct and overhead costs as listed and defined hereunder:" Subparagraph (17) of this paragraph indicates that AFUDC is to be included in the construction cost of a plant asset. Staff notes that the Company does not follow this requirement. The Company calculates AFUDC and records the debt and equity components in accounts 3013, and 3016, respectively. (See Schedule 2, Page 2 of 5.)

Staff recommends that the Company comply with the FERC UsoA by including its AFUDC accruals in the total cost of its constructed plant assets.

Q. What is Staff recommending concerning the non-compliance with the FERC Uniform System of Accounts Gas Plant Instruction No. 3?

A. Staff recommends that the Company file an affidavit within 60 days of the date of the Decision resulting from this proceeding.

The affidavit should assert the Company's compliance with the FERC Uniform System of Accounts, Gas Plant Instruction No. 3.

AFUDC - Debt

Q. Did you make any adjustments to account number 3013, AFUDC Debt?

A. Yes. Please refer to Schedule 2, Page 2 of 5. Staff increased this account by $5,447, from $21,932 to $27,379 to reflect Staff's calculation of the Test Year AFUDC debt accrual. Staff's calculation is shown on Schedule 2, Page 3 of 5. Staff determined the average CWIP balance and the average short-term debt balance from transactions recorded in the Company's general ledger.

AFUDC-Equity

Q. Did you make any adjustments to account number 3016, AFUDC Equity?

A. Yes. Please refer to Schedule 2, Page 2 of 5. Staff decreased this account by $11,928, from $554,217 to $542,289 to reflect Staff's calculation of the Test Year AFUDC equity accrual. Staff's calculation is shown on Schedule 2, Page 3 of 5. Staff determined the average CWIP balance and the average short-term debt balance from transactions recorded in the Company's general ledger.

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Franchises and Consents

Q. Did you make any adjustments to account number 3020, Franchises and Consents?

A. Yes. Please refer to Schedule 2, Page 2 of 5. Staff decreased this account by $4,536, from $286,863 to $282,327 in order to remove an invoice that had been recorded twice for legal services provided to obtain a franchise agreement with the City of Phoenix.

Miscellaneous Intangible Plant

Q. Did you make any adjustments to account number 3030, Miscellaneous Intangible?

A. Yes. Please refer to Schedule 2, Page 3 of 5. Staff increased the Miscellaneous Intangible Plant account by $541,450, from $5,833 to $547,283. Staff reclassified $613,116 from account no. 3010, Intangible Plant – Organization.

Staff also removed $32,468 due to the Company's inability to provide documentation to support the amount.

Additionally, Staff removed $39,198 for refunds made on an advance.

General Land and Land Rights

Q. Did you make any adjustments to account no. 3890, General Land and Land Rights?

A. Yes. Please refer to Schedule 2, Pages 2 and 4. Staff decreased this account by $275,851, from $502,044 to $226,193. The $502,044 was the total purchase price (including fees) paid for a building and land adjacent to the Company's headquarters. The contract for the winning bid awarded for the remodeling of the building (data request MSJ-145) stated "Contractor agrees to construct and complete in a workmanlike manner a COMMERCIAL BUILDING ADDITION AND RENOVATION OF EXISTING BUILDING". Based upon an appraisal provided by the Company, Staff reclassified $261,000 to account no. 3900, Structures and Improvements to reflect the portion of the $502,044 that was incurred for the building. FERC Gas Plant Instruction no. 7 F states:

The cost of buildings and other improvements (other than public improvements) shall not be included in the land accounts. If at the time of acquisition of an interest in land such interest extends to buildings or other improvements (other than public improvements), which then are devoted to utility operations, the land and improvements shall be separately appraised and the cost allocated to land and buildings on the basis of the appraisals. If the improvements are removed or wrecked without being used in operations, the cost of the removing or wrecking shall be charged and the salvage credited to the account in which the cost of the land is credited.

Staff reclassified one half of the fees (i.e. $1,022) to account no. 3900, Structures and Improvements. Additionally, Staff removed $13,829 for the square footage that was removed for the office space that was occupied by the Company's unregulated Lake Powell Propane and Gas Connection businesses as shown on Schedule 2, Page 4 of 5.

General Structures and Improvements

Q. Did you make any adjustments to account no. 3900, Structures and Improvements?

A. Yes. Please refer to Schedule 2, Pages 2 and 4. Staff increased this account by $246,925, from $217,547 to $464,472 to reclassify the portion of the $502,044 that was for the building and fees. Additionally, Staff removed $13,829 for the square footage that was removed for the office space that was occupied by the Company's unregulated Lake Powell Propane and Gas Connection businesses as shown on Schedule 2, Page 4 of 5.

Accumulated Depreciation

Q. Did you make any adjustments to the Company's accumulated depreciation balance?

A. Yes. Please refer to Schedule 2, Pages 1 and 5. Staff increased this account by $4,116, from $3,110,191 to $3,114,307. The Company proposed a pro-forma addition to accumulated depreciation to reflect one full year of depreciation expense on its 1999

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plant additions. Staff increased the 1999 depreciable plant addition as a result of reclassifying the cost incurred for a building that was originally classified as land.

Materials and Supplies Inventories

Q. Did you make any adjustments to the materials and supplies inventories balance?

A. Yes. I decreased this account by $5,517, from $162,057 to $156,540 in order to remove an invoice for fuel stock that should have been recorded in one of the Company's nonregulated businesses.

Construction Work In Progress ("CWIP")

Q. Did you make any adjustments to the Company's CWIP?

A. Yes. I decreased this account by $282,035, from $282,035 to $0. As discussed earlier in my testimony, none of the construction projects were completed, placed in service, removed from the CWIP account and the total cost of the projects transferred into the appropriate plant accounts by Staff's cut-off date of August, 31, 2000.

Contributions In Aid Of Construction

Q. Did any matters come to your attention while auditing the Company's contributions in aid of construction account balance?

A. Yes. During the audit, Staff noted that the Company includes nonrefundable contributions in aid of construction in its plant accounts. This is not allowed under the FERC. The FERC Gas Plant Instruction No. 2, "Gas plant to be recorded at cost", paragraph D states:

The gas plant accounts **shall not** include the cost or other value of gas plant contributed to the company. Contributions in the form of money its equivalent toward the construction of gas plant shall be credited to the accounts charged with the cost of such construction. Plant constructed from contribution of cash or its equivalent **shall be** shown as a reduction to gross plant constructed when assembling cost data in work orders for posting to plant ledger accounts" (emphasis added).

Q. What are you recommending concerning these problems?

A. Staff recommends the Company comply with the FERC Uniform System of Accounts by removing CIAC costs from plant prior to posting to plant general ledger accounts within 60 days of the date of Decision resulting from this proceeding.

Cash Working Capital

Q. What is cash working capital and how should it be calculated?

A. Cash working capital is the amount of cash needed to pay for the daily operating expenses needed to provide service during a test year. For Class A companies such as BMG, cash working capital is generally determined through a lead lag study. When the result of the study produces a positive amount, it indicates that on the average, the investors of the utility are paying for expenses before it receives the cash from ratepayers. A positive cash working capital amount is added to rate base.

Alternatively, a negative cash working capital amount indicates that on the average, the utility is receiving cash from ratepayers prior to paying for expenses. In this case, the cash to pay expenses is provided by sources other that the utility's investors (i.e. by ratepayers) and, therefore, should be deducted from rate base.

Q. What are you recommending concerning cash working capital in the Company's next rate case?

A. The Company has proposed a $0 cash working capital in this rate case. For its next rate case, Staff recommends that the Company perform a lead lag study at a reasonable cost to determine its cash working capital needs. This study will enable the Company to quantify its cash working capital needs, identify whether the cash working capital was investor or ratepayer provided, and to determine whether the amount should be added to or deducted from rate base.

REVENUE ADJUSTMENT SUMMARY

Q. Would you please summarize your adjustments to revenue?

A. Yes, please refer to Schedule 3, Page 1 of 5. My adjustments to total gas sales revenue resulted in a net decrease of $833,208, from $5,777,147 to $4,943,939.

REVENUE ADJUSTMENTS

Q. On September 26, 2000, the Company filed amended schedules that increased its Test Year present rate revenue by $783,736. The Company proposed a higher base cost of gas in order to reflect its projected higher purchased gas cost. Did you accept the Company's proposal?

A. No, please refer to adjustment A shown on Schedule 3, Page 1 of my testimony and adjustment E shown on Schedule 1, Page 2 of my testimony. While Staff accepted the Company's proposal to increase its purchased gas expense, Staff did not accept the Company's proposal to increase its present rate revenue. In general, Staff does not make this type of adjustment to Test Year present rate revenue as (1) it would not appropriately reflect the decrease in operating income that would result when a higher than actual purchased gas expense is used and (2) it would not appropriately reflect the percentage increase in Commission authorized base rate revenue needed to cover the additional gas cost.

Q. Did you make any adjustments to the Company's Gas Sales Revenue?

A. Yes, please refer to adjustment B shown on Schedule 4, Page 1, of my testimony and adjustments A and D shown on Schedule 1, Page 2 of 5, of my testimony. I decreased the Company's proposed Test Year gas sales revenue by $49,472, from $4,993,465 to

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$4,943,993 in order to remove the Company's net fuel adjustor revenues from its base rate revenue.

As shown on Schedule 1, Page 2 of 5 (adjustments A and D), the $49,472 was derived by combining the Company's $134,094 in revenue generated by its "frozen" fuel adjustor rate with the ($84,622) in revenue exclusions generated by its "rolling average" fuel adjustor rate; for a net fuel adjustor balance of $49,472.

Q. Did you accept the Company's $260,660 annualization adjustment increase to present rate revenues?

A. Yes, Staff has accepted the $260,660 annualization adjustment to include revenues resulting from customer growth that occurred during the Test Year. The Company has grown by 691 customers (or 13.39 percent), from 5,161 customers at the beginning of the Test Year to 5,852 customers at the end of the Test Year.

Q. Did you accept the Company's proposal to increase Test Year revenues by $40,496?

A. Staff calculated its Test year present rate revenue using the billing determinants provided by the Company. When this amount was compared to the Company's revenue, Staff's Test Year present rate revenue was $40,496 higher. Therefore, the Company's $40,496 adjustment was already included in Staff's calculation of the Company's revenue.

Q. Did you make any adjustments to the Company's Other Operating Revenue?

A. No. Other Operating Revenue which represents revenue generated from the Company's service related charges was accepted as reported.

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EXPENSE ADJUSTMENT SUMMARY

Q. Would you please summarize your adjustments to expenses?

A. Yes, please refer to Schedule 4, Page 1 of 4. My total adjustments to expenses resulted in a net decrease of $295,528, from $8,783,672 to $8,488,144.

EXPENSE ADJUSTMENTS - DETAIL

Incentive Bonuses

Q. Did Staff accept the Company's proposal to include incentive bonuses in its operating expenses and plant in service?

A. No. The Company first began its incentive program during the Test Year (i.e. 1999). Staff did not accept the Company proposal because the incentive bonus program is a discretionary form of compensation to the employee as the amount paid to the employee is neither fixed, regular nor even certain to occur. Staff believes these types of expenses are more appropriately recorded below-the-line and, therefore, removed $35,918 in incentive bonus expenses from operating expenses and $21,413 in capitalized incentive bonus expenses from plant in service.

Q. Why did Staff not accept the Company's proposal to include incentive bonuses in its plant in service and operating expenses?

A. In general terms, forms of incentive compensation represent methods of providing monetary compensation to the work force through an unguaranteed bonus or alternative compensation program, in addition to base wages. These programs are typically tied, in part, to targeted financial results, service quality and employee performance. The ratemaking recognition of incentive compensation serves to virtually eliminate company risk of loss for the amounts included in revenue requirement at ratepayer expense.

Theoretically, employees are motivated to perform well because, if the incentive target levels are not achieved, they will not receive incentive compensation pay. Recognizing that merit increases, workforce reduction and promotions affect a company's total payroll costs, it is generally accepted that employees will continue to receive their base compensation irrespective of the company's earnings or achieved target levels, provided their work continues to be satisfactory. However, incentive programs require certain conditions other than satisfactory work to precede or trigger the payout of the bonus compensation, thereby presumably placing an employee "at risk" for that portion of his/her compensation.

If minimum targets or thresholds are not met, employees do not receive incentive payments and the amount of incentive compensation included in rates only increases the Company's profits. If the targets met are at levels lower than those reflected in rates, employees only receive incentive payments commensurate with levels actually achieved and any difference increases Company profits. Regardless of the level of incentive compensation included in the cost of service, ratepayers would nevertheless be required to fund the allowed level of incentive plan costs – regardless of whether or not the intended benefits were realized or any pay-outs occurred during the period rates were in effect.

Under each of these situations, ratepayers would be "at risk" to fund the incentive plan costs included in regulated rates regardless of pay-out, while employees would be "at risk" because targets might not be achieved for any number of reasons. At the same time, any incentive payouts below the levels included in and recovered through revenue requirement would flow through and contribute to the Company's net income.

By setting rates to include incentive compensation, the annual intra-company debate would be who gets the ratepayers' money – the employees or the Company and its shareholders. In Staff's opinion, shareholders benefit through increased profits, revenue and cashflow resulting from employees improving their performance in pursuit of incentive compensation payments. As such, shareholders should be "at risk" or responsible for the potential incentive compensation. In Staff's opinion, the inclusion of incentive compensation in rates would not put shareholders "at risk".

Post Merger Liability

Q. What is the Company's post merger liability?

A. The post merger liability is a $393,260 expense incurred for a severance package for the former CEO of the old Black Mountain Gas as a result of the merger of NSP with the old Black Mountain Gas. The $393,260 is being amortized over 36 months beginning in March of 1999.

The Company included $109,240 or (10 months) of the expense in its Test Year operating expenses. Staff believes these types of expenses are more appropriately recorded below-the-line and, therefore, Staff removed the portion that was expensed in the Test Year ($109,240). Although this amount was allocated to most accounts in the Company's general ledger, Staff removed an equal amount (i.e. $27,310) from the Company's four largest salaries and wages expense accounts (i.e. accts. 8701, 9011, 9111, and 9200). Staff also notes that the Company will no longer incur this expense approximately eight or nine months after the new rates are in effect.

Purchased Gas

Q. Did you make any adjustments to account 5000, Gas Cost of Sales?

A. Yes. Please refer to Schedule 3, Pages 1 and 2. Staff decreased this account by $236,128, from $2,184,555 to $1,948,427. Beginning with the $1,347,304 recorded in the Company's general ledger, Staff added $53,515 due to the Company's annualization adjustment and also added $783,736 for the Company's projected increase in its purchased gas cost. Ordinarily, Staff does not adopt a projected gas cost as the amount to be included in rates. However, due to the volatile nature in the cost of gas, Staff is adopting the gas projection. This projection was adopted by Staff Witness, Robert Gray, who is sponsoring testimony on the cost of purchased gas.

Staff calculated the $236,128 decrease shown on Schedule 3, Page 2, by reconciling the $1,347,304 amount in the general ledger account 5000, Gas Cost of Sales, to the Company's actual gas purchases recorded in account no. 1910, Deferred Purchased Gas, that were supported by invoices (i.e. $1,102,282). Staff then added back $8,893 for a credit on a Southwest Gas invoice that was pursuant to an advance agreement. The total of these two amounts (i.e. $1,102,282 + 8,893 = $1,111,176) was subtracted from $1,347,304 which resulted in a decrease of $236,128.

Fuel Adjustor Revenues

Q. Did you make any adjustments to account 5020, Purchase Gas Adjustment revenues?

A. Yes. Please refer to Schedule 3, Pages 1 and 2. Staff decreased this account by $59,379, from $59,379 to $0 to remove costs recorded as a result of the Company's fuel adjustor mechanism. Staff believes that it is inappropriate to include or exclude revenues generated by a fuel adjustor mechanism in test year revenues or expenses as a permanent over- or under-collection of revenue would be built into the base rate.

Operating Wages and Expenses

Q. Did you make any adjustments to account 8701, Operating Wages and Expenses Salaries?

A. Yes. Please refer to Schedule 3, Pages 1 and 2. Staff decreased this account by $40,011, from $159,134 to $119,123 as a result of removing incentive bonuses and post merger liability expenses.

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Customer Accounting Salaries and Wages

Q. Did you make any adjustments to account 9011, Customer Accounting Salaries and Wages?

A. Yes. Please refer to Schedule 3, Pages 1 and 2. Staff decreased this account by $42,449, from $136,773 to $94,324 as a result of removing incentive bonuses, post merger liability expenses, and the one-time expense for wages of summer college interns who helped relieve some of the backlog caused by the computer conversion.

Sales Promotion Salaries and Wages

Q. Did you make any adjustments to account 9111, Sales Promotion Salaries and Wages?

A. Yes. Please refer to Schedule 3, Pages 1 and 3. Staff decreased this account by $30,902, from $56,943 to $26,041 as a result of removing incentive bonuses and post merger liability expenses.

Advertising Expense

Q. Did you make any adjustments to account 9130, Advertising Expense?

A. Yes. Please refer to Schedule 3, Pages 1 and 3. Staff decreased this account by $18,617, from $41,252 to $22,635 as a result of removing costs that were incurred for sponsorships, donations, non-employee cash awards, and image building. Staff believes that these costs are more appropriately recorded below-the-line.

Administrative Salaries and Wages

Q. Did you make any adjustments to account 9200, Administrative Salaries and Wages?

A. Yes. Please refer to Schedule 3, Pages 1 and 3. Staff decreased this account by $41,677, from $242,407 to $200,730 as a result of removing incentive bonuses and post merger liability expenses.

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Professional Services

Q. Did you make any adjustments to account 9230, Professional Services?

A. Yes. Please refer to Schedule 3, Pages 1 and 3. Staff decreased this account by $44,741, from $184,977 to $140,236. Staff removed (a) $22,773 for consulting services performed by the former CEO of the old Black Mountain Gas that were for projects that will not be re-occurring (b) $10,240 for a marketing study that will not be re-occurring (c) removed $9,750 for an employee recruitment fee, and $1,977 (i.e. $1,428 + 549) for summer college intern help used to relieve the backlog caused by the computer conversion.

Employee Benefits

Q. Did you make any adjustments to account 9260, Employee Benefits?

A. Yes. Please refer to Schedule 3, Pages 1 and 3. Staff decreased this account by $6,449, from $123,582 to $117,133 as a result removing costs incurred for bottled water, food, donations, etc. Staff believes these types of expenses are more appropriately recorded below-the-line.

Miscellaneous General and Administrative Expense

Q. Did you make any adjustments to account 9302, Miscellaneous General and Administrative Expense?

A. Yes. Please refer to Schedule 3, Pages 1 and 3. Staff decreased this account by $5,010, from $44,090 to $39,080. This adjustment was the result of removing expenses incurred for memberships to non-utility related clubs and boards.

Travel and Entertainment

Q. Did you make any adjustments to account 9390, Travel and Entertainment?

A. Yes. Please refer to Schedule 3, Page 1 and 3. Staff increased this account by $2,500, from $101,972 to $99,995. This adjustment was the result of adding the cost of a regulatory accounting class that is to be taken by Company personnel.

Depreciation and Amortization Expense

Q. Did you make any adjustments to account no. 4030, Depreciation and Amortization Expense?

A. Yes. Please refer to Schedule 3, Pages 1 and 5. Staff decreased this account by $10,034, from $581,110 to $571,076 as a result of changes made to plant and to two depreciation rates. Staff proposed to reduce the depreciation rate of account no. 3030, Miscellaneous Intangible Plant from 20 percent to 3.33 percent as Staff's reclassifications to this account (i.e. $541,450) consists primarily of mains. Further, for account no. 3910, Office Furniture and Equipment, Staff recommends establishing a new depreciation rate of 4.82 percent for non-computer office furniture and equipment. Staff reviewed the depreciation rates in effect for non-computer office furniture and equipment for Southwest Gas Corporation and Citizens Utilities Company – Northern Gas Division and found their rates to be 2.73 percent and 4.82 percent, respectively.

Property Taxes

Q. Did you make any adjustments to account 9430, Property Taxes?

A. Yes. Please refer to Schedule 3, Pages 1 and 4. Staff decreased this account by $13,605, from $212,052 to $225,657 as a result of using the Company's most recent (i.e. 2000) property tax billings.

Corporate Expense Allocation

Q. Did you make any adjustments to account 4265, Corporate Expense Allocation?

A. Yes. Please refer to Schedule 3, Page 1 and 4. Staff decreased this account by $2,004, from $26,276 to $24,272. Staff removed costs incurred for federal regulation as these costs relate to the part of NSP's business that fall under federal jurisdiction. Staff also removed the year 2000 computer project as it is not a recurring expense.

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Interest On Long-term Debt

Q. Did you make any adjustments to the Interest on Long-term Debt balance?

A. Yes. Please refer to Schedule 3, Pages 1 and 4. Staff decreased this account by $2,004, from $26,276 to $24,272 as a result of reflecting Staff's synchronized interest calculation which is rate base multiplied by weighted cost of debt (i.e. $10,594,827 x .015).

RATE DESIGN

Q. Have you prepared a Schedule detailing the Company's and Staff's present and proposed rate design?

A. Yes. Please refer to Schedule 5, Pages 1 through 3.

Q. What proposed revenue was used to develop Staff's proposed rates?

A. Using the cost of capital rate of 9.61 percent determined by Staff's cost of capital witness, Joel Reiker, and the Staff adjusted Test Year rate base, revenues, and expenses, Staff determined a total revenue requirement of $5,457,687. This revenue requirement represents an increase of $513,748 over Staff adjusted Test Year revenue as shown on Schedule 1, Page 3 of 5.

Q. Did Staff use the Company's cost of service study as a guide in determining Staff's proposed rate design?

A. Yes. Staff witness, Marlin Scott, conducted Staff's cost of service study. The results of this analysis indicated that the Company's revenue allocation was not unreasonable. Therefore, Staff used the Company's revenue allocation as a guide to allocate Staff's proposed increase of $513,748.

Q. How has Staff developed its proposed rate design?

A. Staff began its rate design by setting the minimum charges for all classes equal to the minimum charges proposed by the Company. However, these charges generated less revenue than that which Staff had recommended for its revenue requirement. Consequently, Staff added $0.08804 to the present rate for all classes (except the compressed natural gas class) to generate the remainder of the revenue.

Service-Related Charges

Q. Did the Company propose any increases in its service-related charges?

A. Yes, please refer to Schedule 4. The Company requested changes in the following service related charges:

Service Charges	Present	Proposed
Establishment of Service	$15.00	$20.00
Re-Connection of Service – Regular Hrs.	$25.00	$30.00
Re-Connection of Service – After Hrs.	$25.00	$45.00
Service Calls Per Hour – Regular Hrs.	$25.00	$30.00
Meter Test Fee – Per Hour (If Correct)	$12.50	$25.00

Q. Did the Company propose any additions to its service-related charges?

A. Yes, please refer to Schedule 5. The Company requested additions of the following service related charges:

Service Charges	Present	Proposed
Meter Re-read – Per Hour (If Correct)	$12.50	$25.00
Service Calls Per Hour – After Hrs.	$25.00	$45.00

Q. Does Staff concur with these changes?

A. Yes. Staff concurs with these changes. Similar to its other rates and charges, the service-related charges need to be revised in accordance with rising labor and other expenses. Further, the increase in the service-related charges will allow the Company to recover costs from the customers who are causing the expense. Additionally, the increase in revenue resulting from these charges will offset the revenue needed from base rates to generate the Company's total revenue requirement.

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CONSUMER SERVICE ISSUES

Q. Please comment on the consumer services issues?

A. Consumer Services Staff report zero complaints from 1995 to 1999 and two complaints against the current application for Black Mountain Gas. There were also zero formal complaints. The Company is in good standing with the Corporations Division and are in compliance with the Utilities Division in filing their annual report. In reviewing the Company's Schedule H-3 under "Present Rate", Consumer Services Staff notes that the "Meter Re-read (If Correct)" charge and the "Service Calls Per Hour – After Hours" are new proposed charges because these charges are not on the Company's current tariff.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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SUMMARY OF FILING

	------Present Rates------		------Proposed Rates------	
	Per Company	Per Staff	Per Company	Per Staff
Operating Revenues:				
Gas Sales Revenue - Base Rates	$ 5,671,105	$ 4,887,369	$ 5,989,113	$ 5,392,947
Other Gas Revenue	$ 56,570	$ 56,570	$ 64,740	$ 64,740
Fuel Adjustor Revenue	$ 49,472	$ -	$ 49,472	$ -
Total Operating Revenue:	$ 5,777,147	$ 4,943,939	$ 6,103,325	$ 5,457,687
Operating Expenses:				
Operation and Maintenance	$ 3,601,532	$ 3,076,664	$ 3,601,532	$ 3,076,664
Depreciation	$ 581,110	$ 571,076	$ 581,110	$ 571,076
Taxes Other than Income	$ 212,052	$ 225,657	$ 212,052	$ 225,657
Income Tax	$ 510,887	$ 510,887	$ 642,011	$ 566,127
Total Operating Expenses:	$ 4,905,581	$ 4,384,284	$ 5,036,705	$ 4,439,524
Operating Income or (Loss)	$ 871,566	$ 559,655	$ 1,066,620	$ 1,018,163
Proposed Revenue Increase Over Staff Adjusted Present TY Rev	-	-	$ 1,159,386	$ 513,748
Proposed Revenue Increase %	-	-	23.45%	10.39%
Rate Base O.C.L.D.	$ 11,100,500	$ 10,594,827	$ 11,100,500	$ 10,594,827
Rate of Return - O.C.L.D.	7.85%	5.28%	9.61%	9.61%

COMPARISON OF PRESENT RATES
Summary

Line No.	Description	COMPANY 1999 ACTUAL PRESENT RATES With Fuel Adj.	Company Pro-forma Adjustments	Company Adjusted Present Rates With Fuel Adj.		Staff Pro-forma Adjustments		STAFF PRESENT RATES Per Billcount Without Fuel Adj.
1a.	Gas Sales Revenue - Base Rates Only	$ 4,576,315	$ 9,898	$ 4,586,213		$ 40,496	B	$ 4,626,709
1b.	Pro-Forma Adjustment - Incr base gas cost ($.42 per therm)	$ -	$ 783,736	$ 783,736		$ (783,736)	E	$ -
1c.	Pro-Forma Adjustment - Annualization of Revenue	$ -	$ 260,660	$ 260,660		$ -		$ 260,660
1d.	Pro-Forma Adjustment - Reconcil. To Billing Determinants	$ -	$ 40,496	$ 40,496		$ (40,496)	C	$ -
1e.	Pro-Forma Adjustment - Net Frozen & Rolling Avg FA Rev	$ 59,370	$ (9,898)	$ 49,472	A	$ (49,472)	D	$ -
1f.	**Revenue Before "Other Gas Sales" Revenue**	**$ 4,635,685**	**$ 1,084,892**	**$ 5,720,577**		**$ (833,208)**		**$ 4,887,369**
1g.	Other Gas Sales Revenue	$ 34,906	$ -	$ 34,906		$ -		$ 34,906
1h.	Revenue Reclassified to "Other Gas Sales"	$ -	$ 21,664	$ 21,664		$ -		$ 21,664
1i.	**Total Revenue - Present Rates**	**$ 4,670,591**	**$ 1,106,556**	**$ 5,777,147**		**$ (833,208)**		**$ 4,943,939**
2.	Operating Expense	**$ 3,751,610**	**$ 370,235**	**$ 4,905,581**		**$ 4,384,284**		**$ 4,384,284**
3.	**Operating Income (Loss)**	**$ 918,981**	**$ 736,321**	**$ 871,566**		**$ (5,217,492)**		**$ 559,655**
4.	Rate Base	$ 11,100,500	$ 11,100,500	$ 11,100,500		**$ (537,991)**		$ 10,594,827
5.	**% Return on Rate Base**	**8.28%**		**7.85%**				**5.28%**

Explanation to Adjustment:

A - $ 134,094 Revenue generated from "Frozen" fuel adjustor rate
$ (84,622) Revenue excluded due to "Rolling Average" fuel adjustor rate
$ 49,472 Actual net "Frozen" and "Rolling Average" fuel adjustor revenue

B - The $40,496 amount is the difference between Staff's billcount and the Company's adjusted present rate revenue.

C - Staff removed the Company's $40,496 pro-forma adjustment as it was already included in the revenue that Staff calculated using the Company provided billing determinant data.

D - Staff removed $49,472 in fuel adjustor revenues. See also adj. "A" above.

E - Staff removed the Company's adjustment to include an increase in the base cost of gas in Test Year present rate revenue as Staff believes this adjustment to Test Year present rate revenue is inappropriate.

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COMPARISON OF PROPOSED REVENUE SUMMARY

Line No.	Description	Company Adjusted* Present Rates W/O Fuel Adj & Base Cost of Gas Inc	COMPANY PROPOSED RATES	STAFF PROPOSED RATES
1a.	Gas Sales Revenue - Base Rates	$ 4,586,213	$ 4,904,221	$ 4,308,055
1b.	Pro-Forma Adjustment - Incr Base Cost of Gas	$ -	$ 783,736	$ 783,736
1c.	Pro-Forma Adjustment - Annualization of Revenue	$ 260,660	$ 260,660	$ 260,660
1d.	Pro-Forma Adjustment - Reconcile To Billing Determinants	$ 40,496	$ 40,496	$ 40,496
1e.	Pro-Forma Adjustment - Net Frozen & Rolling Avg FA Rev	$ -	$ 49,472	$ -
1f.	Revenue Before "Other Gas Revenue"	$ 4,887,369	$ 6,038,585	$ 5,392,947
1g.	Other Gas Revenue	$ 56,570	$ 64,740	$ 64,740
1h.	**Total Revenue**	**$ 4,943,939**	**$ 6,103,325**	**$ 5,457,687**
2.	Operating Expense	$ 4,905,581	$ 5,036,705	$ 4,439,524
3.	Operating Income (Loss)	$ 38,358	$ 1,066,620	$ 1,018,163
4.	Rate Base	$ 11,100,500	$ 11,100,500	$ 10,594,827
5.	% Return on Rate Base	0.35%	9.61%	9.61%
6.	**Proposed Revenue Increase Over Total Present Rates**	-	**$ 1,159,386**	**$ 513,748**
7.	**% Increase Over Total Present Rates**	-	**23.45%**	**10.39%**

* Does not include Company's proposed adjustment to the base cost of gas for Test Year present rate revenue.

	Calculation of Pro-Forma Income Taxes	
Staff Adjusted Test Year Revenues	$ 4,943,939	
Less: Staff Adjusted Test Year Operating Exp.	$ (3,647,740)	
Less: Staff Adjusted Property Taxes	$ (225,657)	
Net Operating Income Before Taxes	$ 1,070,542	
Less: Synchronized Interest on Long-term debt	$ (143,030)	
Taxable Income	$ 927,511	
Combined State and Federal Income Tax Rates	0.3928	From Schedule 1, Page 5 of 5
Income Taxes	$ 364,327	
Plus: Taxes on Proposed Revenue Increase	$ 201,800	See Below for Calculation
Staff Proposed Income Tax Expense	**$ 566,127**	

Calculation of Net Operating Income Before Revenue Increase Due to Taxes

Staff Adjusted Test Year Revenues	$ 4,943,939
Less: Test Year Operating Expenses	$ (3,647,740)
Less: Property Taxes	$ (225,657)
Net Operating Income Before Taxes	$ 1,070,542
Less: Income Taxes	$ (364,327)
Net Operating Income (Loss)	$ 706,215

Calculation of Required Revenue Increase Due To Increase In Income Taxes

Staff Proposed Rate Base	$ 10,594,827
Staff Proposed Rate of Return	9.61%
Required Net Operating Income	$ 1,018,163
Actual Net Operating Income	$ 706,215
Net Operating Income Deficiency/(Excess)	$ 311,948
Gross Revenue Conversion Factor	1.6469
Required Revenue Increase (Decrease)	**$ 513,748**
Combined State and Federal Income Tax Rates	0.3928
Income Tax on Revenue Increase (Decrease)	**$ 201,800**

REVENUE CONVERSION FACTOR CALCULATION

	100%	Gross Revenue Change
	0.00	Less: Uncollectible Revenue
	0.00	Less: Gross Revenue Taxes
	100.00%	
	39.28%	Less: Federal and State Income Taxes (see below for calculation)
	60.72%	Change in Net Operating Income

100% / 60.72% = 1.646904 Gross Revenue Conversion Factor

	$ 1.00	One Dollar of Operating Income
x	0.08	Multiplied by: Flat State Tax Rate on $1.00 of Operating Income
	$ 0.08	**State Tax On $1.00 of Operating Income**
	$ 1.00	One Dollar of Operating Income
-	0.08	Less: State Tax On $1.00 of Operating Income
	$ 0.92	Federal Taxable Income After State Tax
x	0.34	Federal Tax Rate
	$ 0.3128	**Federal Tax On $1.00 of Operating Income**
	$ 0.0800	State Income Taxes
	0.3128	Federal Income Taxes
	$ 0.3928	**Combined State and Federal Taxes**

ORIGINAL COST RATE BASE

Plant In Service	Per Company	Adjustments		Per Staff
Gross Utility Plant in Service	$ 15,745,435	$ (111,610)	A	$ 15,633,825
Company Pro-forma Adjustment	$ 91,046	$ (91,046)	B	$ -
Total Utility Plant in Service	$ 15,836,481	$ (202,656)		$ 15,633,825
Less: Accumulated Depreciation	$ 3,110,191	$ 4,116	C	$ 3,114,307
Net Utility Plant In Service	$ 12,726,290	$ (198,540)		$ 12,519,519
Less Deductions:				
Total Net Advances	$ 831,656	$ -		$ 831,656
Total Net Contributions	$ 673,542	$ -		$ 673,542
Deferred Income Taxes	$ 679,121	$ -		$ 679,121
Customer Security Deposits	$ 82,563	$ -		$ 82,563
Total Deductions	$ 2,266,882	$ -		$ 2,266,882
Plus Additions:				
Materials and Supplies Inventory	$ 162,057	$ (5,517)	D	$ 156,540
Construction Work In Progress (CWIP)	$ 282,035	$ (282,035)	E	$ -
Remodeling Costs of New Building	$ 197,000	$ (11,350)	F	$ 185,650
Total Additions	$ 641,092	$ (298,902)		$ 342,190
RATE BASE	$ 11,100,500	$ (497,442)		$ 10,594,827

Explanation of Adjustments:

A - Staff decreased plant as shown and discussed on the "Original Cost Plant Adjustment" Sch 2, Page 2.

B - Staff disallowed the Company's $91,046 pro-forma adjustment to plant as it related to (1) net salary and professional services increases due to an annualization adjustment and (2) incentive bonuses.

C - Staff increased the accumulated depreciation balance as shown and discussed on the "Accumulated Depreciation Adjustment" Schedule 2, Page 5.

D - Staff decreased the materials and supplies inventory balance due to removing an item that should have been recorded in one of the Company's unregulated businesses.

E - Staff disallowed the Company's pro-forma adjustment to include $282,000 in CWIP in rate base as it did not meet Staff's criteria for inclusion as discussed in the OCRB section of staff witness, Crystal Brown's testimony.

F - Staff decreased the remodeling costs as a result of removing the cost per square foot of the Company's two unregulated businesses that are occupying space in the newly remodeled building.

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ORIGINAL COST PLANT ADJUSTMENT

	Per Company	Staff Adjustments		Per Staff
Intangible Plant				
3010 Organization	$ 628,562	$ (613,116)	A	$ 15,446
3013 AFUDC - Debt	$ 21,932	$ 5,447	D	$ 27,379
3016 AFUDC - Equity	$ 554,217	$ (11,928)	D	$ 542,289
3020 Franchises and Consents	$ 286,863	$ (4,536)	B	$ 282,327
3030 Miscellaneous Intangible Plant	$ 5,833	$ 541,450	C	$ 547,283
Subtotal Intangible Plant	$ 1,497,407	$ (82,684)		$ 1,414,723
Distribution Plant				
3740 Land and Land Rights	$ 5,903	$ -		$ 5,903
3750 Structures and Improvement	$ -	$ -		$ -
3760 Mains	$ 8,660,801	$ -		$ 8,660,801
3780 Measuring & Regulating Equip - General	$ 189,903	$ -		$ 189,903
3800 Services	$ 2,254,729	$ -		$ 2,254,729
3810 Meters	$ 808,720	$ -		$ 808,720
3820 Meter Installations	$ 363,128	$ -		$ 363,128
3830 House Regulators	$ 19,154	$ -		$ 19,154
3840 House Regulators Installations	$ 55,837	$ -		$ 55,837
3850 Industrial Meas & Regulating Station Equip	$ 971	$ -		$ 971
3860 Other Property On Customers Premises	$ 245	$ -		$ 245
3870 Other Equipment	$ 3,874	$ -		$ 3,874
3880 Interest Capitalized	$ 1,986	$ -		$ 1,986
Subtotal Distribution Plant	$ 12,365,251	$ -		$ 12,365,251
General Plant				
3890 Land and Land Rights	$ 502,044	$ (275,851)	E	$ 226,193
3900 Structures and Improvement	$ 217,547	$ 246,925	F	$ 464,472
3910 Office Furniture and Fixtures	$ 578,893	$ -		$ 578,893
3920 Transportation Equipment	$ 314,030	$ -		$ 314,030
3940 Tools, Shop, & Garage Equipment	$ 128,483	$ -		$ 128,483
3960 Power Operated Equipment	$ 23,116	$ -		$ 23,116
3970 Communication Equipment	$ 40,578	$ -		$ 40,578
3980 Miscellaneous Equipment	$ 10,026	$ -		$ 10,026
3990 Other Tangible Property	$ 68,060	$ -		$ 68,060
Subtotal General Plant	$ 1,882,777	$ (28,926)		$ 1,853,851
Total Utility Plant In Service	**$ 15,745,435**	**$ (111,610)**		**$ 15,633,825**

The explanations to the adjustments are shown on Schedule 2, Pages 3 and 4.

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Explanation to the Plant Adjustments

Cross Ref.	Account Number	Account Description		Amount	Explanation		
A -	3010	Organization	$	257,468	Advance - reclass to misc intangible plant		
			$	355,648	Advance - reclass to misc intangible plant		
			$	613,116			
B -	3020	Franchises and Consents	$	(4,536)	Staff removed the amount as it had been double counted.		
C -	3030	Misc. Intangible Plant	$	257,468	Advance - reclass from organization		
			$	(32,468)	Advance - removed for lack of support		
			$	355,648.00	Advance - reclass from organization		
			$	(39,198.12)	Southwest Gas Refund to BMG on advance		
			$	541,450			
D -	3013	AFUDC - Debt Addition	$	5,447	$983,394 x .020643 =	$20,300	Per Staff
						$14,853	Per Co.
						$5,447	Difference
	3016	AFUDC - Equity Addition	$	(11,928)	$983,394 x .075434 =	$74,148	Per Staff
						$86,076	Per Co.
						($11,928)	Difference

AFDC-Equity Rate:

Annual Rate

Ae=[1-S/W] x [p(P/D+P+C)+c(C/D+P+C)] = 0.075433951

Monthly Rate

Ae=[1-S/W] x [p(P/D+P+C)+c(C/D+P+C)] = 0.075433951 / 12 mos. = 0.006286

AFDC-Debt Rate:

Annual Rate

Ai=s x (S/W) + d(D/D+C+P)(1-(S/W))= 0.020643156

Monthly Rate

Ai=s x (S/W) + d(D/D+C+P)(1-(S/W))= 0.020643156 / 12 mos. = 0.00172

Where:

Ae = AFDC Equity rate
Ai = AFDC Debt rate

S =	125,000	= Average Short-term Debt
s =	0.06	= Cost of short-term debt
p =	0	= Preferred Stock Cost Rate
P =	0	= Preferred Stock
D =	3,000,000	Long-term Debt
d =	0.06	Cost of Long-term Debt
c =	0.115	Common Equity rate
C =	9,070,826	Common Equity
W =	983,395	Average Construction Work in Progress

Explanation to the Plant Adjustments Continued

E -	3890 General Land & Land Rights	$ (261,000.00)	Removal of bldg and reclass to acct #3900
		$ (2,044.00)	Removal of fees
		$ 1,022.00	Allocation of half of fees to acct #3900
		$ (13,829.00)	Removal of squ ft of unregulated businesses
		$ (275,851.00)	
F -	3900 General Struct & Improv	$ 261,000.00	Reclass of bldg from acct no #3900
		$ 1,022.00	Allocation of half of fees to acct #3900
		$ (15,097.00)	Removal of squ ft of unregulated businesses
		$ 246,925.00	

The square footage that was removed for spaced occupied by the Company's unregulated Lake Powell Propane and Gas Connection businesses were calculated based upon the Company's response to data request CSB 1-154.

	Acct. 389 Land and Fees	Acct. 390 Building and Fees	Remodeling Costs	Total
Cost per plant asset	$ 240,022	$ 262,022	$ 197,000	$ 699,044
Divided by total squ footage	4,900	4,900	4,900	4,900
Cost per item per squ foot	$ 48.98	$ 53.47	$ 40.20	$ 142.66
Squ Ft of Lake Powell Office	100.76	100.76	100.76	
Squ Ft of Gas Conn Office	181.56	181.56	181.56	
Total Squ Ft to be Removed	282.32	282.32	282.32	
Total Cost for Lake Powell	$ 4,936	$ 5,388	$ 4,051	$ 14,375
Total Cost for Gas Conn	$ 8,894	$ 9,709	$ 7,299	$ 25,902
Total Cost to be Removed	**$ 13,829**	**$ 15,097**	**$ 11,350**	$ 40,276

ACCUMULATED DEPRECIATION ADJUSTMENT

	Amount
Accumulated Depreciation - Per Staff	$ 3,114,307
Accumulated Depreciation - Per Company	$ 3,110,191
Total Adjustment	$ 4,116

Explanation to Adjustment:
Staff increased the Company's pro-forma adjustment to accumulated depreciation as a result of reclassifying cost incurred for a building that was previously classified as land.

	1999 Additions Per Company	Adj	1999 Additions Per Staff	Depr. Rates	Depr Exp For 1999 Additions
3010 Organization	$ 14,723	$ -	$ 14,723	4.00%	$ 588.92
3013 AFUDC - Debt	$ 14,853	$ -	$ 14,853	3.33%	$ 495.10
3016 AFUDC - Equity	$ 86,076	$ -	$ 86,076	3.33%	$ 2,869.20
3020 Franchises and Consents	$ 189,044	$ -	$ 189,044	10.00%	$ 18,904.40
3760 Mains	$ 1,475,488	$ -	$ 1,475,488	3.33%	$ 49,182.93
3780 Measuring & Regulating Equip	$ 14,869	$ -	$ 14,869	3.33%	$ 495.63
3800 Services	$ 329,135	$ -	$ 329,135	3.33%	$ 10,971.17
3810 Meters	$ 141,357	$ -	$ 141,357	3.33%	$ 4,711.90
3890 Land and Land Rights	$ 502,044	$ (275,851)	$ 226,193	0.00%	$ -
3900 Structures and Improvement	$ -	$ 246,925	$ 246,925	3.33%	$ 8,230.83
3910 Office Furniture and Fixtures	$ 364,557	$ -	$ 364,557	20.00%	$ 72,911.40
3920 Transportation Equipment	$ 10,925	$ -	$ 10,925	20.00%	$ 2,185.00
3940 Tools, Shop, & Garage Equipmen	$ 15,658	$ -	$ 15,658	12.50%	$ 1,957.25
3970 Communication Equipment	$ 8,034	$ -	$ 8,034	10.00%	$ 803.40
	$ 3,166,763	$ (28,926)	$ 3,137,837		$ 174,307.14
				1/2 of Total	$ 87,153.57

1999 Addtns Depr Exp - Per Staff	$ 87,153.57
1999 Addtns Depr Exp - Per Company	$ (83,038.00)
	$ 4,115.57

INCOME STATEMENT
PRESENT RATES

Acct. No.	Operating Revenue		Per Company		Adjustments			Per Staff
	Gas Sales Revenue - Base Rates	$	5,671,105	$	(783,736)	A	$	4,887,369
	Fuel Adjustor Revenue	$	49,472	$	(49,472)	B	$	-
	Other Electric Revenue	$	56,570	$	-		$	56,570
	Total Operating Revenue:	$	5,777,147	$	(833,208)		$	4,943,939
Acct. No.	**Operating Expenses**							
5000	Purchased Gas	$	2,184,555	$	(236,128)	C	$	1,948,427
5020	Purchased Gas Adjustment	$	59,379	$	(59,379)	D	$	-
8701	Operating Wages and Expenses	$	159,134	$	(40,011)	E	$	119,123
8740	Mains & Services Expense	$	11,060	$	-		$	11,060
8800	Other Distribution Expense	$	1,554	$	-		$	1,554
8851	Maintenance Salaries and Wages	$	50,730	$	-		$	50,730
8860	Maintenance Structures and Improvements	$	13,711	$	-		$	13,711
8870	Maintenance of Mains	$	7,405	$	-		$	7,405
8880	Maintenance of Vaporizer	$	44	$	-		$	44
8920	Maintenance of Services	$	3,241	$	-		$	3,241
8930	Maintenance of Meters	$	3	$	-		$	3
8940	Maintenance of Other Equipment	$	28,027	$	-		$	28,027
9011	Customer Accounting Salaries and Wages	$	136,773	$	(42,449)	F	$	94,324
9030	Customer Records Expense	$	5,449	$	-		$	5,449
9040	Uncollectible Accounts	$	(371)	$	-		$	(371)
9050	Miscellaneous Customer Accounting Expense	$	6,973	$	-		$	6,973
9080	Customer Service Expense	$	4,282	$	-		$	4,282
9090	Customer Information Expense	$	9,710	$	-		$	9,710
9100	Miscellaneous Customer Assistance Expense	$	19,240	$	-		$	19,240
9111	Sales Promotion Salaries and Wages	$	56,943	$	(30,902)	G	$	26,041
9130	Advertising Expense	$	41,252	$	(18,617)	H	$	22,635
9160	Miscellaneous Sales Expense	$	3,215	$	-		$	3,215
9200	Administrative Salaries and Wages	$	242,407	$	(41,677)	I	$	200,730
9210	Office Supplies and Expense	$	17,761	$	-		$	17,761
9230	Professional Services	$	184,977	$	(44,741)	J	$	140,236
9240	Property Insurance	$	1,848	$	-		$	1,848
9250	Liability Insurance	$	23,007	$	-		$	23,007
9260	Employee Benefits	$	123,582	$	(6,449)	K	$	117,133
9280	Regulatory Commission Expense	$	-	$	-		$	-
9290	Other Administrative Supplies	$	4,292	$	-		$	4,292
9301	General Advertising Expense	$	225	$	-		$	225
9302	Miscellaneous Gen. & Admin. Expense	$	44,090	$	(5,010)	L	$	39,080
9310	Rent Expense	$	29,811	$	-		$	29,811
9320	Maintenance of General Plant	$	2	$	-		$	2
9360	Telephone Expense	$	29,362	$	-		$	29,362
9370	Utilities Expense	$	7,206	$	-		$	7,206
9380	Auto and Truck Expense	$	21,266	$	-		$	21,266
9390	Travel and Entertainment	$	9,932	$	2,500	M	$	12,432
9391	Business Meals	$	5,903	$	-		$	5,903
9410	Postage	$	20,670	$	-		$	20,670
4030	Depreciation Expense	$	581,110	$	(10,034)	N	$	571,076
9430	Property Taxes	$	212,052	$	13,605	O	$	225,657
9400	Other Taxes	$	6,606	$	-		$	6,606
4265	Corporate Expense Allocation	$	26,276	$	(2,004)	P	$	24,272
4091	Income Taxes	$	510,887	$	-		$	510,887
	Total Operating Expenses	$	4,905,581	$	(521,297)		$	4,384,284
	Net Operating Income (Loss)	$	871,566	$	(311,911)		$	559,655
	Other Income and Expense							
	Interest Income	$	-	$	-		$	-
	Other Income	$	-	$	-		$	-
	Other Expenses	$	-	$	-		$	-
	Interest Expense on L.T. Debt	$	-	$	143,030	Q	$	143,030
	Net Other Income and Expense	$	-	$	(143,030)		$	(143,030)
	Net Income (Loss)	$	871,566	$	(454,942)		$	416,624

For the explanation to the adjustments, see Sch. 3, Pages 3 through 5.

EXPLANATION TO INCOME STATEMENT ADJUSTMENTS

A -	Gas Sales Revenue - Base Rates	- Per Company	$ 5,671,105	
		- Per Staff	$ 4,887,369	$ (783,736)

To remove the Company's pro-forma adjustment to increase the base cost of gas from Test Year present rate revenue.

B -	Fuel Adjustor Revenues	- Per Company	$ 49,472	
		- Per Staff	$ -	$ (49,472)

To remove revenue generated through the Company's PGA mechanism from Test Year present rate revenues.

C -	Purchased Gas	- Per Company	$ 2,184,555	
		- Per Staff	$ 1,948,427	$ (236,128)

To reflect Staff's calculation of the Company's 1999 purchased gas expense.

$	1,347,304	1999 Purchased gas expense per the Company's G/L
$	53,515	Annualization adjustment increase
$	(236,128)	Expenses with no supporting invoices and interest on fuel bank
$	783,736	Projected increase in the purchased gas expense
$	1,948,427	

D -	Purchased Gas Adjustment	- Per Company	$ 59,379	
		- Per Staff	$ -	$ (59,379)

To remove purchased gas costs calculated as a result of the Company's PGA mechanism.

E -	Operating Salaries & Wages	- Per Company	$ 159,134	
		- Per Staff	$ 119,123	$ (40,011)

To reflect the removal of expenses that Staff believes is more appropriately recorded below-the-line.

$	12,701	Incentive bonuses
$	27,310	Post merger liablity
$	40,011	

F -	Cust Accounting Salaries & Wages	- Per Company	$ 136,773	
		- Per Staff	$ 94,324	$ (42,449)

To reflect the removal of expenses that Staff believes is more appropriately recorded below-the-line.

$	5,388	Incentive bonuses
$	27,310	Post merger liablity
$	4,064	College interns used during computer conversion (CSB 5-161)
$	5,687	College interns used during computer conversion (CSB 5-161)
$	42,449	

EXPLANATION TO INCOME STATEMENT ADJUSTMENTS
Continued

G -	Sales Promotion Salaries and Wages	- Per Company	$	56,943	
		- Per Staff	$	26,041	$ (30,902)

To reflect the removal of expenses that Staff believes are more appropriately recorded below-the-line.

$	3,592	Incentive bonuses
$	27,310	Post merger liablity
$	30,902	

H -	Advertising Expense	- Per Company	$	41,252	
		- Per Staff	$	22,635	$ (18,617)

To reflect the removal of expenses that Staff believes are more appropriately recorded below-the-line.

$	15,617	Sponsorships, donations, etc.
$	3,000	Non-employee cash awards
$	18,617	

I -	Administrative Salaries and Wages	- Per Company	$	242,407	
		- Per Staff	$	200,730	$ (41,677)

To reflect the removal of expenses that Staff believes are more appropriately recorded below-the-line.

$	14,367	Incentive bonuses
$	27,310	Post merger liablity
$	41,677	

J -	Professional Services	- Per Company	$	184,977	
		- Per Staff	$	140,236	$ (44,741)

To reflect the removal of expenses that Staff believes are more appropriately recorded below-the-line.

$	22,773	Total Tracker (related to Tom Leneau, non-recurring expense)
$	10,240	Marketing Study (non-recurring expense)
$	9,750	Empl Recruitment Fee (non-recurring expense)
$	1,428	College intern use for computer conversion (CSB 5-161)
$	549	College intern use for computer conversion (CSB 5-161)
$	44,740	

K -	Employee Benefits	- Per Company	$	123,582	
		- Per Staff	$	117,133	$ (6,449)

To reflect the removal of expenses that Staff believes are more appropriately recorded below-the-line (I.e bottled water, food, donations).

L -	Miscellaneous Gen. & Admin. Expense	- Per Company	$	44,090	
		- Per Staff	$	39,080	$ (5,010)

To reflect the removal of expenses that Staff believes are more appropriately recorded below-the-line.

$	210	Kiwanis Club membership (KFR 1-133)
$	4,800	Alternative Board membership (KFR 1-133)
$	5,010	

EXPLANATION TO INCOME STATEMENT ADJUSTMENTS
Continued

M -	Travel and Entertainment	- Per Company	$	9,932	
		- Per Staff	$	12,432	$ 2,500

To reflect cost of regulatory accounting training class to be taken by company employee.

N -	Depreciation Expense	- Per Company	$	581,110	
		- Per Staff	$	571,076	$ (10,034)

To reflect Staff's calculation of the Company's depreciation expense as shown in detail on Schedule 3, Page 5 of 5.

O -	Property Tax Expense	- Per Company	$	212,052	
		- Per Staff	$	225,657	$ 13,605

To reflect the Company's most recent property tax billing.

P -	Corporate Expense Allocation	- Per Company	$	26,276	
		- Per Staff	$	24,272	$ (2,004)

To remove expenses related to federal regulation and Y2K computer projects.

$	9.49	Federal regulation costs
$	16.96	Federal regulation costs
$	1,977.87	Year 2000 computer project
$	2,004	

Q -	Interest Expense on L.T. Debt	- Per Company	$	-	
		- Per Staff	$	143,030	$ 143,030

To reflect Staff's synchronization of interest (I.e. rate base x weighted cost of debt).

Depreciation Expense Calculation

	Original Cost Plant Per Staff	Fully Depr Plant Per Co.	Depreciable Plant Per Staff	Proposed Depreciation Rate	Depreciation Expense
Intangible Plant					
3010 Organization	$ 15,446	$ -	$ 15,446	4.00%	$ 617.84
3013 AFUDC - Debt	$ 27,379	$ -	$ 27,379	3.33%	$ 911.72
3016 AFUDC - Equity	$ 542,289	$ -	$ 542,289	3.33%	$ 18,058.22
3020 Franchises and Consents	$ 282,327	$ 27,684	$ 254,643	10.00%	$ 25,464.26
3030 Miscellaneous Intangible Plant	$ 547,283	$ 5,692	$ 541,591	3.33% A	$ 18,034.98
Subtotal Intangible Plant	$ 1,414,723	$ 33,376	$ 1,381,347		$ 63,087.02
Distribution Plant					
3740 Land and Land Rights	$ 5,903	$ -	$ 5,903	0.00%	$ -
3750 Structures and Improvement	$ -	$ -	$ -	3.33%	$ -
3760 Mains	$ 8,660,801	$ 48,135	$ 8,612,666	3.33%	$ 286,801.78
3780 Measuring & Regulating Equip - General	$ 189,903	$ -	$ 189,903	3.33%	$ 6,323.77
3800 Services	$ 2,254,729	$ 13,883	$ 2,240,846	3.33%	$ 74,620.17
3810 Meters	$ 808,720	$ 15,722	$ 792,998	3.33%	$ 26,406.83
3820 Meter Installations	$ 363,128	$ -	$ 363,128	3.33%	$ 12,092.16
3830 House Regulators	$ 19,154	$ 8,012	$ 11,142	3.33%	$ 371.03
3840 House Regulators Installations	$ 55,837	$ 1,124	$ 54,713	3.33%	$ 1,821.94
3850 Industrial Meas & Regulating Station Equip	$ 971	$ -	$ 971	3.33%	$ 32.33
3860 Other Property On Customers Premises	$ 245	$ -	$ 245	3.33%	$ 8.16
3870 Other Equipment	$ 3,874	$ -	$ 3,874	3.33%	$ 129.00
3880 Interest Capitalized	$ 1,986	$ -	$ 1,986	3.33%	$ 66.13
Subtotal Distribution Plant	$ 12,365,251	$ 86,876	$ 12,278,375		$ 408,673.32
General Plant					
3890 Land and Land Rights	$ 226,193	$ -	$ 226,193	0.00%	$ -
3900 Structures and Improvement	$ 464,472	$ -	$ 464,472	3.33%	$ 15,466.92
3910 Office Furniture and Fixtures	$ 211,718	$ 164,056	$ 47,662	4.82% B	$ 2,297.31
3910 Office Furniture and Fixtures - Computer	$ 367,175	$ 131,135	$ 236,040	20.00%	$ 47,208.00
3920 Transportation Equipment	$ 314,030	$ 36,929	$ 277,101	12.50%	$ 34,637.63
3940 Tools, Shop, & Garage Equipment	$ 128,483	$ -	$ 128,483	12.50%	$ 16,060.38
3960 Power Operated Equipment	$ 23,116	$ 22,456	$ 660	10.00%	$ 66.00
3970 Communication Equipment	$ 40,578	$ 15,419	$ 25,159	12.50%	$ 3,144.88
3980 Miscellaneous Equipment	$ 10,026	$ 10,026	$ -	20.00%	$ -
3990 Other Tangible Property	$ 68,060	$ 53,744	$ 14,316	20.00%	$ 2,863.20
Subtotal General Plant	$ 1,853,851	$ 433,765	$ 1,420,086		$ 121,744.30
Total	**$ 15,633,825**	**$ 554,017**			**$ 593,505**

	$ 15,633,825	Total Plant
	$ 232,096	Less: Land and Land Rights
	$ 554,017	Less: Fully Depreciated Plant
	$ 14,847,712	Depreciable Plant
Composite Depr Rate:	4.00%	Depr Exp divided by Depreciable Plant
CIAC Original Balance:	$ 673,542	CIAC Original Balance
	$ -	Less: Non Amortizable Contributions
	$ -	Less: Fully Amortized Contributions
	$ 673,542	
CIAC Amortization Rate:	3.33%	
CIAC Amortization Expense	$ 22,429	

Staff's Pro Forma Annual Depreciation Expense:

$ 593,505	Depr. Exp. Before CIAC Amort. Exp. Deduction
$ 22,429	Less: CIAC Amortization Expense
$571,075.69	**Pro Forma Annual Depreciation Expense**

Explanation of Adjustments

A - Staff recommends lowering the amortization rate of acct. no 3030, Misc Intangile plant from 20% to 3.33%.

B - Staff recommends establishing a new depr rate of 4.82% for non-computer office furniture and equipment.

Black Mountain Gas
Docket No. G-03703A-00-0283
Test Year Ended: December 31, 1999

Schedule 4

BUNDLED
RATE DESIGN

Residential	Present Rates	---Proposed Rates--- Per Company	Per Staff
Standard Rate:			
Monthly Service Charge	$5.50	$6.00	$6.00
Commodity Rate per Therm	$0.8702	$1.07940	$0.95824
Gas Air Conditioning:			
Monthly Service Charge	$5.50	$6.00	$6.00
Commodity Rate per Therm	$0.3500	$0.51060	$0.43804
Compressed Natural Gas:			
Monthly Service Charge	$6.00	$6.00	$6.00
Commodity Rate per Therm	$0.0400	$0.55000	$0.55000
Commercial			
Standard Rate:			
Monthly Service Charge	$10.00	$15.00	$15.00
Commodity Rate per Therm	$0.8702	$1.05080	$0.95824
Resort:			
Monthly Service Charge	$22.95	$30.00	$30.00
Commodity Rate per Therm	$0.8702	$1.05080	$0.95824
Co-Generation:			
Monthly Service Charge	$10.00	$30.00	$30.00
Commodity Rate per Therm	$0.3260	$0.48000	$0.41404

Service Charges:	Present Rates	---Proposed Rates--- Per Company	Per Staff
Establishment of Service	$ 15.00	$ 20.00	$ 20.00
Re-establishment (Within 12 months)	(a)	(a)	(a)
Re-Connection of Service - Regular Hours	$ 25.00	$ 30.00	$ 30.00
Re-Connection of Service - After Hours	$ 25.00	$ 45.00	$ 45.00
Service Calls Per Hour - Regular Hours	$ 25.00	$ 30.00	$ 30.00
Service Calls Per Hour - After Hours	N/A	$ 45.00	$ 45.00
Meter Re-read Charge (If Correct)	N/A	$ 25.00	$ 25.00
Meter Test Fee - Per Hour (If Correct)	$ 12.50	$ 25.00	$ 25.00
NSF Check	$ 10.00	$ 15.00	$ 15.00
Late Charge (Per Month)	1.5%	1.5%	1.5%
Deposit - Residential	(b)	(b)	(b)
Deposit - Commercial	(c)	(c)	(c)
Deferred Payment (Per Month)	1.5%	1.5%	1.5%

(a) Number of Months Off System times Monthly Minimum Charge (A.A.C. R14-2-403.B)
(b) Two times the Average Monthly Bill (A.A.C. R14-2-403.B)
(c) Two and one-half times the Average Monthly Bill (A.A.C. R14-2-403.B)
N/A Not applicable as these charges are not on the Company's current tariff.

TYPICAL BILL ANALYSIS
Residential

	Avg Therms Used Per Bill	Present Rates*	Proposed Rates	Dollar Increase	Percent Increase
Company Proposed					
Residential	59	$ 56.84	$ 69.68	$ 12.84	22.59%
Staff Proposed					
Residential	59	$ 56.84	$ 62.54	$ 5.69	10.02%

Residential

		Company		Staff	
Therm Consumption	Present Rates*	Proposed Rates	% Change	Proposed Rates	% Change
0	$ 5.50	$ 6.00	9.09%	$ 6.00	9.09%
5	$ 9.85	$ 11.40	15.69%	$ 10.79	9.54%
10	$ 14.20	$ 16.79	18.25%	$ 15.58	9.72%
15	$ 18.55	$ 22.19	19.61%	$ 20.37	9.81%
20	$ 22.90	$ 27.59	20.45%	$ 25.16	9.87%
30	$ 31.61	$ 38.38	21.44%	$ 34.75	9.94%
40	$ 40.31	$ 49.18	22.00%	$ 44.33	9.98%
50	$ 49.01	$ 59.97	22.36%	$ 53.91	10.00%
60	$ 57.71	$ 70.76	22.62%	$ 63.49	10.02%
70	$ 66.41	$ 81.56	22.80%	$ 73.08	10.03%
80	$ 75.12	$ 92.35	22.95%	$ 82.66	10.04%
90	$ 83.82	$ 103.15	23.06%	$ 92.24	10.05%
100	$ 92.52	$ 113.94	23.15%	$ 101.82	10.06%
110	$ 101.22	$ 124.73	23.23%	$ 111.41	10.06%
120	$ 109.92	$ 135.53	23.29%	$ 120.99	10.07%

*The present rates do not include fuel adjustor revenue generated by the fuel adjustor mechanism.

TYPICAL BILL ANALYSIS
Gas Air Conditioning

	Avg Therms Used Per Bill	Present Rates*	Proposed Rates	Dollar Increase	Percent Increase
Company Proposed					
Gas Air Conditioning	523	$ 188.55	$ 273.04	$ 84.49	44.81%
Staff Proposed					
Gas Air Conditioning	523	$ 188.55	$ 235.09	$ 46.54	24.69%

Gas Air Conditioning		Company		Staff	
Therm Consumption	Present Rates*	Proposed Rates	% Change	Proposed Rates	% Change
0	$ 5.50	$ 6.00	9.09%	$ 6.00	9.09%
10	$ 9.00	$ 11.11	23.40%	$ 10.38	15.34%
50	$ 23.00	$ 31.53	37.09%	$ 27.90	21.31%
100	$ 40.50	$ 57.06	40.89%	$ 49.80	22.97%
200	$ 75.50	$ 108.12	43.21%	$ 93.61	23.98%
300	$ 110.50	$ 159.18	44.05%	$ 137.41	24.35%
400	$ 145.50	$ 210.24	44.49%	$ 181.22	24.55%
500	$ 180.50	$ 261.30	44.76%	$ 225.02	24.66%
750	$ 268.00	$ 388.95	45.13%	$ 334.53	24.82%
1,000	$ 355.50	$ 516.60	45.32%	$ 444.04	24.91%
1,500	$ 530.50	$ 771.90	45.50%	$ 663.06	24.99%

*The present rates do not include fuel adjustor revenue generated by the fuel adjustor mechanism.

Black Mountain Gas
Docket No. G-03703A-00-0283
Test Year Ended: December 31, 1999

TYPICAL BILL ANALYSIS
Commercial

	Avg Therms Used Per Bill	Present Rates*	Proposed Rates	Dollar Increase	Percent Increase
Company Proposed					
Commercial	437	$ 390.28	$ 474.20	$ 83.92	21.50%
Staff Proposed					
Commercial	437	$ 390.28	$ 433.75	$ 43.47	11.14%

Commercial		Company		Staff	
Therm Consumption	Present Rates*	Proposed Rates	% Change	Proposed Rates	% Change
10	$ 18.70	$ 25.51	36.39%	$ 24.58	31.44%
50	$ 53.51	$ 67.54	26.22%	$ 62.91	17.57%
100	$ 97.02	$ 120.08	23.77%	$ 110.82	14.23%
150	$ 140.53	$ 172.62	22.83%	$ 158.74	12.96%
200	$ 184.04	$ 225.16	22.34%	$ 206.65	12.28%
250	$ 227.55	$ 277.70	22.04%	$ 254.56	11.87%
300	$ 271.06	$ 330.24	21.83%	$ 302.47	11.59%
350	$ 314.57	$ 382.78	21.68%	$ 350.38	11.39%
400	$ 358.08	$ 435.32	21.57%	$ 398.30	11.23%
450	$ 401.59	$ 487.86	21.48%	$ 446.21	11.11%
500	$ 445.10	$ 540.40	21.41%	$ 494.12	11.01%
550	$ 488.61	$ 592.94	21.35%	$ 542.03	10.93%
750	$ 662.65	$ 803.10	21.20%	$ 733.68	10.72%
1,000	$ 880.20	$ 1,065.80	21.09%	$ 973.24	10.57%
1,500	$ 1,315.30	$ 1,591.20	20.98%	$ 1,452.36	10.42%

*The present rates do not include fuel adjustor revenue generated by the fuel adjustor mechanism.

Black Mountain Gas
Docket No. G-03703A-00-0283
Test Year Ended: December 31, 1999

TYPICAL BILL ANALYSIS
Resort

	Avg Therms Used Per Bill	Present Rates*	Proposed Rates	Dollar Increase	Percent Increase
Company Proposed					
Resort	991	$ 885.32	$ 1,071.34	$ 186.02	21.01%
Staff Proposed					
Resort	991	$ 885.32	$ 979.62	$ 94.30	10.65%

Resort		Company		Staff	
Therm Consumption	Present Rates*	Proposed Rates	% Change	Proposed Rates	% Change
10	$ 31.65	$ 40.51	27.98%	$ 39.58	25.05%
50	$ 66.46	$ 82.54	24.20%	$ 77.91	17.23%
100	$ 109.97	$ 135.08	22.83%	$ 125.82	14.42%
150	$ 153.48	$ 187.62	22.24%	$ 173.74	13.20%
200	$ 196.99	$ 240.16	21.91%	$ 221.65	12.52%
250	$ 240.50	$ 292.70	21.70%	$ 269.56	12.08%
300	$ 284.01	$ 345.24	21.56%	$ 317.47	11.78%
350	$ 327.52	$ 397.78	21.45%	$ 365.38	11.56%
400	$ 371.03	$ 450.32	21.37%	$ 413.30	11.39%
450	$ 414.54	$ 502.86	21.31%	$ 461.21	11.26%
500	$ 458.05	$ 555.40	21.25%	$ 509.12	11.15%
550	$ 501.56	$ 607.94	21.21%	$ 557.03	11.06%
750	$ 675.60	$ 818.10	21.09%	$ 748.68	10.82%
1,000	$ 893.15	$ 1,080.80	21.01%	$ 988.24	10.65%
1,500	$ 1,328.25	$ 1,606.20	20.93%	$ 1,467.36	10.47%

*The present rates do not include fuel adjustor revenue generated by the fuel adjustor mechanism.

TYPICAL BILL ANALYSIS
Co-Generation

	Avg Therms Used Per Bill	Present Rates*	Proposed Rates	Dollar Increase	Percent Increase
Company Proposed					
Co-Generation	4,174	$ 1,370.72	$ 2,033.52	$ 662.80	48.35%
Staff Proposed					
Co-Generation	4,174	$ 1,370.72	$ 1,758.20	$ 387.48	28.27%

Co-Generation

Therm Consumption	Present Rates*	Company Proposed Rates	Company % Change	Staff Proposed Rates	Staff % Change
100	$ 42.60	$ 78.00	83.10%	$ 71.40	67.62%
300	$ 107.80	$ 174.00	61.41%	$ 154.21	43.05%
500	$ 173.00	$ 270.00	56.07%	$ 237.02	37.01%
1,500	$ 499.00	$ 750.00	50.30%	$ 651.06	30.47%
2,000	$ 662.00	$ 990.00	49.55%	$ 858.08	29.62%
2,500	$ 825.00	$ 1,230.00	49.09%	$ 1,065.10	29.10%
3,000	$ 988.00	$ 1,470.00	48.79%	$ 1,272.12	28.76%
3,500	$ 1,151.00	$ 1,710.00	48.57%	$ 1,479.14	28.51%
4,000	$ 1,314.00	$ 1,950.00	48.40%	$ 1,686.16	28.32%
4,500	$ 1,477.00	$ 2,190.00	48.27%	$ 1,893.18	28.18%
5,000	$ 1,640.00	$ 2,430.00	48.17%	$ 2,100.20	28.06%
5,500	$ 1,803.00	$ 2,670.00	48.09%	$ 2,307.22	27.97%
6,000	$ 1,966.00	$ 2,910.00	48.02%	$ 2,514.24	27.89%
6,500	$ 2,129.00	$ 3,150.00	47.96%	$ 2,721.26	27.82%
7,000	$ 2,292.00	$ 3,390.00	47.91%	$ 2,928.28	27.76%
8,000	$ 2,618.00	$ 3,870.00	47.82%	$ 3,342.32	27.67%

*The present rates do not the Company's fuel adjustor rate generated by its fuel adjustor mechanism.

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Commissioner

IN THE MATTER OF THE APPLICATION OF BLACK MOUNTAIN GAS COMPANY, CAVE CREEK OPERATIONS, FOR A HEARING TO DETERMINE THE EARNINGS OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES	DOCKET NO. G-03703A-00-0283

DIRECT

TESTIMONY

OF

JOEL M. REIKER

AUDITOR

UTILITIES DIVISION

NOVEMBER, 2000

JBC103T

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SUMMARY OF TESTIMONY
BLACK MOUNTAIN GAS COMPANY – CAVE CREEK OPERATIONS
DOCKET NO. G-03703A-00-0283
RATE OF RETURN
JOEL REIKER

1. Staff concurs with the Company in recommending a capital structure consisting of 23.15 percent long-term debt and 76.85 percent common equity.

2. Staff concurs with the Company in recommending a cost of debt of 5.82 percent.

3. Staff concurs with the Company in recommending a cost of equity of 10.75 percent. This is the same cost of equity recommended by Staff in Black Mountain's previous rate case involving its Page Division, which was adopted by the Commission. Staff believes that an equity cost of 10.75 percent is reasonable for this utility.

4. Based on Black Mountain's capital structure and capital costs, Staff is recommending an overall weighted cost of capital of 9.61 percent, the same cost of capital requested by the Company.

Introduction

Q. Please state your name, occupation, and business address.

A. My name is Joel M. Reiker. I am an Auditor III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division. My business address is 1200 West Washington, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Auditor III.

A. In my capacity as an Auditor III, I make recommendations on the ratemaking implications of proposed mergers and acquisitions that involve utilities that are regulated by the Commission and support them with evidence that is obtained through research and data requests. I also perform studies to determine the cost of capital for utilities that are seeking rate relief and I analyze ACC regulated utilities that have requested approval of financing matters.

Q. Please describe your educational background and professional experience.

A. In 1998, I graduated Cum Laude from Arizona State University, receiving a Bachelor of Science degree in Global Business with a specialization in Finance. My course of studies included classes in corporate and international finance, investments, accounting, and economics. In 1999, after working as an internal auditor for one year, I was employed by the Commission as an Auditor III in the Accounting & Rates Section's Financial Analysis Unit. Since that time, I have attended various seminars and classes on general regulatory and business issues, including cost of capital and energy derivatives.

Q. What is the purpose of your testimony in this case?

A. I will address the appropriate capital structure, as well as the appropriate cost of debt and equity to be recommended for use in setting rates for the Black Mountain Gas Company's Cave Creek Operations ("BMG" or "Company").

. . .

Q. Please summarize your recommendations.

A. I recommend that the Commission adopt a capital structure of 23.15 percent debt and 76.85 percent common equity. I also recommend the Commission adopt a cost of debt of 5.82 percent and a cost of equity of 10.75 percent, for a weighted cost of capital of 9.61 percent. Schedule JMR-1 summarizes my recommendations.

CAPITAL STRUCTURE

Q. What is the Company's proposed Test Year capital structure?

A. The company proposes a capital structure consisting of 23.15 percent long-term debt, and 76.85 percent common equity.

Q. Is this the same capital structure reported in the Company's 1999 Annual Report to the Commission?

A. No. According to the Company's 1999 Annual Report on file with the Commission, Black Mountain had total common equity of $9,819,058, compared to $9,959,563 reported in its application, a difference of $140,505. According to the Company's Controller, Chad Lucas, the difference was due to adjustments that were not discovered prior to finalization of the fiscal year-end close. For total capital structure reporting purposes, Staff believes the difference is immaterial.

Q. How does the Company's proposed Test Year capital structure compare to Staff's recommended capital structure for Black Mountain?

A. I have chosen to use the same capital structure proposed by the company in its application.

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Q. How does Black Mountain's capital structure compare with that of other investor-owned gas distribution companies?

A. Black Mountain's capital structure reflects much less financial risk compared to the capital structures of other investor-owned, publicly traded gas distribution companies. Schedule JMR-2 illustrates the capital structures of nine publicly traded gas distribution companies followed by Value Line. According to the schedule, the average capital structure of the publicly-traded gas distribution companies is approximately 49 percent debt and 51 percent common equity, compared to Black Mountain's capital structure of 23.15 percent debt and 76.85 percent equity.

Q. Do you believe that Black Mountain's capital structure is reasonable?

A. Yes. I believe Black Mountain's capital structure is reasonable because it reflects little financial risk compared to other investor-owned gas distribution companies.

Cost of Debt

Q. What is Black Mountain requesting for its embedded cost of debt?

A. The Company is requesting an embedded cost of debt of 5.82 percent. This represents the interest on revenue bonds less the interest income from the bond sinking fund, divided by the $3.0 million balance of debt.

Q. What cost of debt are you recommending?

A. I am recommending the same cost of debt requested by the Company. Interest expense related to Black Mountain's $3,000,000 IDA Bond was $174,549, net of sinking fund interest income ($180,000 - $5,451 = $174,549), resulting in an imbedded debt cost of 5.82 percent.

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Q. Do you believe that Black Mountain's proposed cost of debt is reasonable?

A. Yes. I believe that Black Mountain's cost of debt is reasonable. It reflects the Company's actual interest expense, and it is well below the current Prime rate of 9.50 percent.

Cost of Equity and Rate of Return on Rate Base

Q. What cost of equity is the Company requesting in this proceeding?

A. The Company is requesting a cost of equity of 10.75 percent.

Q. Did the Company conduct a formal cost of equity study in support of its request?

A. No. Black Mountain's request is based on Staff's recommended cost of equity for the Company's Page operations in its 1999 rate case.

Q. Did the Commission adopt Staff's recommended cost of equity of 10.75 percent in the aforementioned rate case?

A. Yes, In Decision No. 62124, dated December 14, 2000, the Commission approved the Settlement Agreement between BMG, the Residential Utility Consumer Office ("RUCO"), and Commission Staff, in which the parties agreed to Staff's recommended cost of equity for BMG's page operations.

Q. Do you feel that a 10.75 percent cost of equity is reasonable for BMG's Cave Creek operations?

A. Yes. Although the economy has slowed slightly and interest rates have edged upward, I believe that a 10.75 percent return on common equity is still within a fair and reasonable range. As a measure of reasonableness, I have provided the actual 1998 and 1999 returns on common equity for the nine publicly traded gas distribution companies used in my capital structure analysis (Schedule JMR-2). According to the schedule, the average return on common equity for the companies in 1998 and 1999 was 10.62 percent, and 10.54 percent, respectively.

Q. What rate of return on rate base is the Company requesting?

A. The Company is requesting a rate of return on rate base of 9.61 percent. This is the same rate of return on rate base I am recommending.

Q. Do you believe that the overall rate of return on rate base is reasonable?

A. Yes. Based on the Company's capital costs, as well as its capital structure, I believe that the overall rate of return on rate base is reasonable.

Q. Does this conclude your direct testimony?

A. Yes it does.

Black Mountain Gas Company
Docket No. G-03703A-00-0283

Schedule JMR-1

Staff's Recommendation
Black Mountain Gas Capital Structure and
Weighted Cost of Capital
December 31, 1999

	Amount	Weight (%)	Cost	Weighted Cost
Long-term Debt	$ 3,000,000	23.15%	5.82%	1.35%
Common Equity	$ 9,959,563	76.85%	10.75%	8.26%
	$12,959,563	100.00%		9.61%

Black Mountain Gas Company
Docket No. G-03703A-00-0283

Schedule JMR-2

Capital Structures
Publicly Traded Gas Distribution Utilities

		Long-Term Debt	Common Equity	
1	AGL Resources	47.94%	52.06%	100.0%
2	Atmos Energy Corp.	50.00%	50.00%	100.0%
3	Cascade Natural Gas	52.21%	47.79%	100.0%
4	Energen Corp.	50.70%	49.30%	100.0%
5	New Jersey Resources	48.75%	51.25%	100.0%
6	Northwest Natural Gas	47.97%	52.03%	100.0%
7	Piedmont Natural Gas	46.20%	53.80%	100.0%
8	Providence Energy	49.54%	50.46%	100.0%
9	South Jersey Industries	49.78%	50.22%	100.0%
	Average	49.23%	50.77%	100.00%
	Black Mountain Gas	23.15%	76.85%	100.00%

Return on Common Equity
Publicly Traded Gas Distribution Utilities

		1999	1998
		%	%
1	AGL Resources	7.90	12.30
2	Atmos Energy Corp.	6.60	14.90
3	Cascade Natural Gas	12.00	8.30
4	Energen Corp.	11.00	11.00
5	New Jersey Resources	14.80	14.40
6	Northwest Natural Gas	9.90	6.00
7	Piedmont Natural Gas	11.80	13.20
8	Providence Energy	9.00	7.30
9	South Jersey Industries	11.90	8.20
	Average	**10.54**	**10.62**
	Staff's recommended cost of equity for BMG	10.75	

BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, AND BLACK MOUNTAIN GAS, A SUBSIDIARY OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, TO DETERMINE EARNINGS FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN FOR THE CAVE CREEK DIVISION	DOCKET NO. G-03703A-00-0283

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

ECONOMIST

UTILITIES DIVISION

November, 2000

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SUMMARY OF DIRECT TESTIMONY
OF ROBERT GRAY
BLACK MOUNTAIN GAS COMPANY – CAVE CREEK DIVISION
DOCKET NO. G-03703A-00-0283
NOVEMBER 22, 2000

I will appear on behalf of the Arizona Corporation Commission Staff and will testify concerning Staff's position and recommendation regarding Black Mountain Gas Company – Cave Creek Division's application for a permanent rate increase, in the area of the base cost of gas. A summary of my recommendation is:

1. Base Cost of Gas – Staff recommends that Black Mountain Gas Company – Cave Creek Division's base cost of gas be set at $0.42 per therm.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert Gray. My business address is 1200 West Washington, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Senior Economist. My duties include the evaluation of natural gas, electric and telecommunications industry issues and formulation of recommendations to the Commission. A copy of my resume is provided in Exhibit RG-1.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. G-03703A-00-0283?

A. Yes I was.

Q. What is the purpose of your testimony?

A. My testimony is concerned with Black Mountain Gas ("BMG") - Cave Creek Division's proposed base cost of natural gas.

BASE COST OF GAS

Q. What is the current base cost of natural gas for the Cave Creek Division?

A. The current base cost of gas for the Cave Creek Division is $0.27 per therm.

Q. What is the function of the base cost of gas in setting the rates BMG's customers pay?

A. The base cost of gas is used as an estimate of the typical cost of natural gas to BMG and is included in BMG's base rates. The base cost of gas accounts for both the commodity cost and the cost of transporting the natural gas from its source to BMG's distribution system. BMG uses a purchased gas adjustor ("PGA") mechanism to account for the changing cost of natural gas.

BMG currently uses a 12 month rolling average PGA mechanism, whereby a new PGA rate is calculated each month. Each month BMG calculates its average cost of natural gas, on a per therm basis, for the most recent 12 months. The monthly PGA rate is then derived by subtracting the base cost of gas from the 12 month average cost of gas. Therefore, over time, the PGA rate and the base cost of gas will in combination account for the total cost of natural gas for BMG.

Q. Has BMG requested a change in the base cost of gas?

A. Yes. In Mr. Neidlinger's Direct Testimony he recommended that the base cost of gas remain at $0.27 per therm. On September 26, 2000 BMG filed a Notice of Filing Amended Schedules. BMG indicated that the purpose of this filing was to propose a change to the base cost of gas to $0.42 per therm to reflect increases in the cost of natural gas.

Q. Please discuss the recent increases in the cost of natural gas.

A. Since the spring of 2000 the cost of natural gas across the country has increased substantially. According to Natural Gas Weekly the cost of natural gas at the Ignacio Station in the San Juan Basin (one of the main supply basins for Arizona) was $2.29 per MMBtu in November 1999. In comparison, the cost at the Ignacio Station for the week of November 13, 2000 was reported as $4.83 per MMBtu and the December 2000 NYMEX futures price for natural gas as of November 16, 2000, was $5.80 per MMBtu. Commonly mentioned factors for the run up in natural gas prices include: low drilling levels by producers in recent years, difficulty in ramping up natural gas production, low storage levels, high oil prices, unusually warm weather in recent winters which depressed demand, and current and future increased demand (particularly for electric generation). Given current market conditions and a review of the New York Mercantile Exchange's natural gas futures market, it appears likely that natural gas prices will remain high throughout the winter 2000-2001 and very possibly beyond. When natural gas prices are highly volatile it is very difficult to accurately set the base cost of gas.

Q. Should the base cost of gas be set based upon the historical cost of natural gas?

A. The historical cost of gas at this point, reported by BMG as $0.3225 per therm at the end of September 2000, still relies heavily on the much lower cost of natural gas during the winter of 1999-2000's heating season. Given the extreme run up in natural gas prices during the spring, summer, and fall of 2000, and the widespread expectation that the cost of natural gas will remain volatile and high in the near future, it appears to be reasonable in this case to take into consideration both historical costs and anticipated future costs in setting a base cost of gas.

Q. Have you reviewed BMG's historical cost of natural gas as well as projections of future natural gas costs?

A. Yes I have.

Q. Based upon your review of past natural gas costs, market conditions, and futures prices, do you agree with BMG's proposal to increase the base cost of gas to $0.42 per therm?

A. Yes. Although it is extremely difficult to project what natural gas prices will be in the future, BMG's proposed base cost of gas of $0.42 per therm appears to be a reasonable compromise between the lower historical cost of natural gas and the higher present and projected costs of natural gas.

Q. Does this conclude your testimony?

A. Yes it does.

RESUME

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)

M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Senior Economist (August 1997 - present), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses of issues related to the natural gas, electric, and telecommunications utilities. Prepare recommendations and present written and oral testimony before the Commission on various utility industry issues. Use statistical techniques such as regression analysis and factor analysis in a variety of studies to forecast and explain causes and effects. Conduct working group activities including organizing meetings, moderating meetings, and analyzing and reporting working group findings.

Testimony

Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.

Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.

Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

Black Mountain Gas Company - Norther States Power Company, Merger (Docket Nos. G-03493A-98-0017, G-01970A-98-0017), Arizona Corporation Commission, 1998.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference

Memberships

National Association of Regulatory Utility Commissioners - Staff Gas Subcommittee

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IN THE MATTER OF THE APPLICATION OF BLACK MOUNTAIN GAS COMPANY, CAVE CREEK OPERATIONS, FOR A HEARING TO DETERMINE THE EARNINGS OF THE COMPANY, THE FAIR VALUE OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES.

DOCKET NO. G-03703A-00-0283

DIRECT TESTIMONY

OF

MARLIN SCOTT, JR.

UTILITIES ENGINEER

UTILITIES DIVISION

NOVEMBER 2000

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SUMMARY OF DIRECT TESTIMONY
OF MARLIN SCOTT, JR.
BLACK MOUNTAIN GAS COMPANY
DOCKET NO. G-03703A-00-0283
NOVEMBER 22, 2000

I will appear on behalf of the Arizona Corporation Commission Staff and will testify concerning Staff's position and recommendation regarding Black Mountain Gas Company's application for a permanent rate increase in the area of the Cost of Service Study. A summary of my recommendation is:

1. Cost of Service Study (COSS) – Staff recommends that Black Mountain Gas Company's COSS cost allocations and factors be accepted along with Staff's adjustments.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Marlin Scott, Jr. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom and in what capacity are you employed?

A. I am employed by the Arizona Corporation Commission as an Utilities Engineer – Water/Wastewater for the Utilities Division.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since November 1987.

Q. What are your responsibilities as a Utilities Engineer – Water/Wastewater?

A. Among other responsibilities, I inspect, investigate and evaluate water and wastewater systems; obtain data, prepare reconstruction cost new and/or original cost studies, cost of service studies and investigative reports; interpret rules and regulations; suggest corrective action and provide technical recommendations on water and wastewater system deficiencies; and provide written and oral testimony on rates and other cases before the Commission.

Q. How many companies have you analyzed for the Utilities Division?

A. I have analyzed approximately 285 companies in various capacities for the Utilities Division.

Q. Have you previously testified before this Commission?

A. Yes, I have testified in 27 proceedings before this Commission.

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Q. What is your educational background?

A. I graduated from Northern Arizona University in 1984 with a Bachelor of Science degree in Civil Engineering Technology.

Q. Briefly describe your pertinent work experience.

A. Prior to my employment with the Commission, I was Assistant Engineer for the City of Winslow, Arizona, for about two years. Prior to that, I was a Civil Engineering Technician with the U. S. Public Health Service in Winslow for approximately six years.

Q. Please state your professional membership, registrations, and licenses.

A. I am a member of the National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Water.

II. PURPOSE OF TESTIMONY

Q. What was your assignment in this rate proceeding?

A. My assignment was to review the Cost of Service Study (COSS) performed by Black Mountain Gas – Cave Creek Operations (BMG).

Q. What is the purpose of this testimony in this proceeding?

A. This testimony will discuss my review of BMG's COSS and present the results of my review along with my recommendations.

Q. Was developing rate design recommendations part of your assignment?

A. No. Rate design should not be confused with COSSs. A COSS is the allocation of costs to each customer class. Rate design is basically the allocation of revenues to each customer class. The COSS is only one of many factors that is considered when determining the appropriate allocation of revenues. Once the revenue allocation is completed, then specific rates are designed to collect those revenues. Staff's rate design witness is Ms. Crystal Brown.

III. COST OF SERVICE STUDY

Q. What is a COSS?

A. In simple terms, a COSS is a determination of cost-causer by customer class; i.e. how much it costs the utility to provide its service to each customer class. The reason for determining the costs incurred by the utility to serve each customer class is to assist in allocating the revenue requirement for each customer class.

For each utility there are several generally accepted methods of conducting a COSS. There is no one "correct" COSS method, but rather a range of reasonable alternatives. This is not to suggest that COSSs are arbitrary; some allocations are clearly more reasonable than others. This is the reason a COSS should be used only as a general guide and as one of several considerations in designing rates.

Q. What was the process you used in reviewing BMG's COSS?

A. There were three steps in my review. First, I reviewed the rate base and expense numbers that BMG used in its COSS to determine if these numbers matched those in the appropriate schedules of the remainder of its application. Next, I studied the COSS itself to gain an understanding of exactly how BMG had set up this particular study and how it worked. Finally, I reviewed the cost allocations used by BMG to determine whether, in my opinion, these were the appropriate methods to use.

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Q. Did you conduct a separate independent COSS?

A. After studying BMG's model, I decided that the best method for my review would be to replicate BMG's COSS and make the appropriate Staff revisions. The results of my COSS are attached to this testimony as Schedule MSJ.

Q. What revisions did you make to BMG's COSS?

A. My revisions reflect Staff's Accounting and Rates adjustments to BMG's filing and these Staff adjustments are shown and highlighted in my schedules.

IV. RECOMMENDATIONS

Q. Based upon your testimony, what is Staff's recommendation regarding the COSS?

A. Staff recommends that BMG's COSS cost allocations and factors be accepted with Staff's adjustments as reflected in my attached COSS schedules.

Q. Does this conclude your pre-filed testimony?

A. Yes it does.

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
COST OF SERVICE SUMMARY - PRESENT RATES
TEST YEAR ENDED DECEMBER 31, 1999

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL
Operating Revenues	$4,943,939	$3,919,989	$1,023,950
Operating Expenses:			
Purchased Gas	$1,948,427	$1,504,168	$444,259
Distribution Expense - Operation	131,737	105,283	26,454
Distribution Expense - Maintenance	103,161	82,951	20,210
Customer Accounts Expense	106,375	103,127	3,248
Customer Service	33,232	32,217	1,015
Sales Promotion	51,891	40,059	11,832
Administrative & General	670,964	567,977	102,987
Depreciation	571,076	469,719	101,357
Property Taxes	225,657	185,606	40,051
Other Taxes	6,606	5,592	1,014
Corporate Expense Allocation	24,272	20,546	3,726
Income Taxes	510,887	383,088	127,799
Total Operating Expenses	$4,384,285	$3,500,333	$883,952
Operating Income	$559,654	$419,656	$139,998
Rate Base	$10,594,827	$8,698,624	$1,896,203
% Return - Present Rates	5.28%	4.82%	7.38%
Return Index	1.00	0.91	1.40

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
COST OF SERVICE SUMMARY - PROPOSED RATES
TEST YEAR ENDED DECEMBER 31, 1999

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL
Operating Revenues	$5,457,687	$4,361,812	$1,095,875
Operating Expenses:			
Purchased Gas	$1,948,427	$1,504,168	$444,259
Distribution Expense - Operation	131,737	105,283	26,454
Distribution Expense - Maintenance	103,161	82,951	20,210
Customer Accounts Expense	106,375	103,127	3,248
Customer Service	33,232	32,217	1,015
Sales Promotion	51,891	40,059	11,832
Administrative & General	670,964	567,977	102,987
Depreciation	571,076	469,719	101,357
Property Taxes	225,657	185,606	40,051
Other Taxes	6,606	5,592	1,014
Corporate Expense Allocation	24,272	20,546	3,726
Income Taxes	566,127	430,594	135,533
Total Operating Expenses	$4,439,525	$3,547,839	$891,686
Operating Income	$1,018,162	$813,973	$204,189
Rate Base	$10,594,827	$8,698,624	$1,896,203
% Return - Proposed Rates	9.61%	9.36%	10.77%
Return Index	1.00	0.97	1.12

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

UNIT COSTS			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
UNIT COSTS - PRESENT RATES:				
DEMAND:				
Amount		$1,894,048	$1,513,704	$380,344
Bills		69,985	67,848	2,137
Therms		5,224,909	4,033,583	1,191,326
Per Bill		$27.06	$22.31	$177.98
Per Therm		$0.36	$0.38	$0.32
COMMODITY:				
Amount		$2,207,333	$1,704,041	$503,292
Per Therm		$0.42	$0.42	$0.42
CUSTOMER:				
Amount		$832,748	$770,360	$62,388
Per Bill		$11.90	$11.35	$29.19
UNIT COSTS - PROPOSED RATES:				
DEMAND:				
Amount		$2,276,146	$1,819,073	$457,073
Per Bill		$32.52	$26.81	$213.89
Per Therm		$0.44	$0.45	$0.38
COMMODITY:				
Amount		$2,207,333	$1,704,041	$503,292
Per Therm		$0.42	$0.42	$0.42
CUSTOMER:				
Amount		$956,364	$880,181	$76,183
Per Bill		$13.67	$12.97	$35.65

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOCATION OF RATE BASE

DESCRIPTION	FACTOR	TOTAL	CUSTOMER CLASS RESIDENTIAL	COMMERCIAL
GROSS PLANT IN SERVICE:				
Demand	D-1	$11,660,083	9,318,621	2,341,461
Commodity	CM-1	0	0	0
Customer - Services	C-1	2,558,063	2,443,542	114,520
Customer - Meters	C-2	940,351	640,632	299,720
Customer - Meter Installations	C-3	475,329	456,267	19,062
Customer - Customer Accounts	C-4	0	0	0
Total		$15,633,826	$12,859,062	$2,774,764
ACCUMULATED DEPRECIATION:				
Demand	D-1	$2,322,725	1,856,298	466,426
Commodity	CM-1	0	0	0
Customer - Services	C-1	509,574	486,761	22,813
Customer - Meters	C-2	187,321	127,616	59,705
Customer - Meter Installations	C-3	94,687	90,890	3,797
Customer - Customer Accounts	C-4	0	0	0
Total		$3,114,307	$2,561,565	$552,742
NET PLANT IN SERVICE		12,519,519	10,297,497	2,222,022
M & S INVENTORIES:				
Demand	D-1	$156,540	125,105	31,435
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	0	0	0
Total		$156,540	$125,105	$31,435
CWIP:				
Demand	D-1	$0	0	0
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	0	0	0
Total		$0	$0	$0
NEW BUILDING:				
Demand	D-1	$138,462	110,658	27,805
Commodity	CM-1	0	0	0
Customer - Services	C-1	30,377	29,017	1,360
Customer - Meters	C-2	11,167	7,607	3,559
Customer - Meter Installations	C-3	5,644	5,418	226
Customer - Customer Accounts	C-4	0	0	0
Total		$185,650	$152,700	$32,950

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOCATION OF RATE BASE			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
CIAC & AIAC:				
Demand	D-1	-$1,122,613	-897,181	-225,432
Commodity	CM-1	0	0	0
Customer - Services	C-1	-246,286	-235,260	-11,026
Customer - Meters	C-2	-90,535	-61,679	-28,856
Customer - Meter Installations	C-3	-45,764	-43,929	-1,835
Customer - Customer Accounts	C-4	0	0	0
Total		-$1,505,198	-$1,238,049	-$267,149
CUSTOMER DEPOSITS:				
Demand	D-1	$0	0	0
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	-82,563	-80,042	-2,521
Total		-$82,563	-$80,042	-$2,521
DEFERRED INCOME TAXES:				
Demand	D-1	-$506,505	-404,794	-101,711
Commodity	CM-1	0	0	0
Customer - Services	C-1	-111,120	-106,146	-4,975
Customer - Meters	C-2	-40,848	-27,829	-13,020
Customer - Meter Installations	C-3	-20,648	-19,820	-828
Customer - Customer Accounts	C-4	0	0	0
Total		-$679,121	-$558,587	-$120,534
TOTAL RATE BASE		$10,594,827	$8,698,624	$1,896,203

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOC. OF INCOME STATEMENT			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
REVENUES:				
Gas Sales - Base Rates		$4,887,369	$3,865,146	$1,022,223
PGA	CM-1	0	0	0
Service Charges & Other Revenue	C-4	56,570	54,843	1,727
Total Revenues		$4,943,939	$3,919,989	$1,023,950
OPERATING EXPENSES:				
Purchased Gas	CM-1	$1,948,427	$1,504,168	$444,259
Distribution Expense - Operation:				
Demand	D-1	$131,737	105,283	26,454
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	0	0	0
Total		$131,737	$105,283	$26,454
Distribution Expense - Maintenance:				
Demand	D-1	$99,917	79,853	20,064
Commodity	CM-1	0	0	0
Customer - Services	C-1	3,241	3,096	145
Customer - Meters	C-2	3	2	1
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	0	0	0
Total		$103,161	$82,951	$20,210
Customer Accounting:				
Demand	D-1	$0	0	0
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	106,375	103,127	3,248
Total		$106,375	$103,127	$3,248
Customer Service:				
Demand	D-1	$0	0	0
Commodity	CM-1	0	0	0

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOC. OF INCOME STATEMENT

DESCRIPTION	FACTOR	TOTAL	CUSTOMER CLASS RESIDENTIAL	COMMERCIAL
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	33,232	32,217	1,015
Total		$33,232	$32,217	$1,015
Sales Promotion:				
Demand	D-1	$0	0	0
Commodity	CM-1	51,891	40,059	11,832
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	0	0	0
Total		$51,891	$40,059	$11,832
Administrative & General:				
Demand	D-1	$254,986	203,783	51,204
Commodity	CM-1	197,907	152,782	45,125
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	218,071	211,412	6,659
Total		$670,964	$567,977	$102,987
Depreciation:				
Demand	D-1	$425,922	340,393	85,529
Commodity	CM-1	0	0	0
Customer - Services	C-1	93,442	89,258	4,183
Customer - Meters	C-2	34,349	23,401	10,948
Customer - Meter Installations	C-3	17,363	16,667	696
Customer - Customer Accounts	C-4	0	0	0
Total		$571,076	$469,719	$101,357
Property Taxes:				
Demand	D-1	$168,300	134,504	33,796
Commodity	CM-1	0	0	0
Customer - Services	C-1	36,923	35,270	1,653

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOC. OF INCOME STATEMENT			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
Customer - Meters	C-2	13,573	9,247	4,326
Customer - Meter Installations	C-3	6,861	6,586	275
Customer - Customer Accounts	C-4	0	0	0
Total		$225,657	$185,606	$40,051
Other Taxes:				
Demand	D-1	$2,510	2,006	504
Commodity	CM-1	1,949	1,504	444
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	2,147	2,081	66
Total		$6,606	$5,592	$1,014
Corporate Allocation:				
Demand	D-1	$9,224	7,372	1,852
Commodity	CM-1	7,159	5,527	1,632
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	7,889	7,648	241
Total		$24,272	$20,546	$3,726
Total Operation Expenses Ex. Inc. Tx.		$3,873,398	$3,117,246	$756,152
Operating Income Ex. Inc. Tx.		1,070,541	802,743	267,798
Percent		100.00%	74.98%	25.02%
Income Taxes - Present Rates		510,887	383,088	127,799
Operating Income - Present Rates		559,654	419,656	139,998
Revenue Requirement		5,457,687	4,361,812	1,095,875
Revenue Increase		513,748	441,823	71,925
Percent Increase		10.51%	11.43%	7.04%
Increase in Income Taxes		55,240	47,506	7,734
Increase In Operating Income		458,508	394,317	64,191
Adjusted Operating Income		1,018,162	813,973	204,189
Return on Rate Base		9.61%	9.36%	10.77%
Return Index		1.00	0.97	1.12

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOC. OF INCOME STATEMENT			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
Revenues - Proposed Rates		5,457,687	4,361,812	1,095,875
Income Taxes - Proposed Rates		566,127	430,594	135,533
UNIT COSTS - PRESENT RATES:				
Rate Base:				
Demand		7,864,780	6,285,453	1,579,327
Commodity		0	0	0
Customer		2,544,397	2,260,471	283,926
Total		10,409,177	8,545,924	1,863,253
Component Costs:				
Demand		1,092,597	873,193	219,405
Commodity		2,207,333	1,704,041	503,292
Customer		573,465	540,009	33,455
Total		3,873,395	3,117,244	756,151
Return - Pres. Rts.:				
Demand		415,444	332,019	83,425
Commodity		0	0	0
Customer		134,404	119,406	14,998
Total		549,847	451,424	98,423
Inc. Taxes - Pres. Rts.:				
Demand		386,007	308,493	77,514
Commodity		0	0	0
Customer		124,880	110,945	13,935
Total		510,887	419,438	91,449
Return - Prop. Rts.:				
Demand		755,805	604,032	151,773
Commodity		0	0	0

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOC. OF INCOME STATEMENT			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
Customer		244,516	217,231	27,285
Total		1,000,321	821,263	179,058
Inc. Taxes - Prop. Rts.:				
Demand		427,744	341,849	85,895
Commodity		0	0	0
Customer		138,383	122,941	15,442
Total		566,127	464,790	101,337

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

FUNCT. OF RATE BASE COMPONENTS

DESCRIPTION	FACTOR	TOTAL	DEMAND	COMMOD.	SERVICES	METERS	MTR. INST.	CUST.
Gross Utility Plant In Service:								
Intangibles:								
Organization		$15,446						
AFUDC - Debt		27,379						
AFUDC Equity		542,289						
Franchises & Consents		282,327						
Misc. Intangible Plant		547,283						
Total Intangibles	F-1	$1,414,724	1,414,724					0
Distribution Plant:								
Distribution Land & Land Rights	F-3	$5,903	5,903					
Dist. Structures & Improvements	F-3	0	0					
Distribution Mains	F-3	8,660,801	8,660,801					
Distribution Measuring & Reg	F-3	189,903	189,903					
Distribution Services	F-4	2,254,729			2,254,729			
Meters	F-5	808,720				808,720		
Meter Installations	F-6	363,128					363,128	
House Regulators	F-5	19,154				19,154		
House Regulators Installations	F-6	55,837					55,837	
Industrial Meas. & Reg	F-5	971				971		
Dist. Property On Cust. Premises	F-3	245	245					0
Other Distribution Equipment	F-3	3,874	3,874					0
Interest Capitalized	F-3	1,986	1,986					0
Total Distribution Plant		$12,365,251	$8,862,712	$0	$2,254,729	$828,845	$418,965	$0
Total Plant Excluding General		$13,779,975	$10,277,436	$0	$2,254,729	$828,845	$418,965	$0
Percent	F-8	100.00%	74.58%	0.00%	16.36%	6.01%	3.04%	0.00%
General Plant:								
General Land & Land Rights		$226,193						
General Structures & Improvements		464,472						
Office Furniture & Equipment		578,893						
Transporation Equipment		314,030						
Tools & Shop Equipment		128,483						
Power Operating Equipment		23,116						
Communication Equipment		40,578						
Miscellaneous Equipment		10,026						
Other Tangible Property		68,060						
Total General Plant	F-8	$1,853,851	$1,382,647	$0	$303,334	$111,506	$56,364	$0
Total Utility Plant In Service		$15,633,826	$11,660,083	$0	$2,558,063	$940,351	$475,329	$0
Percent	F-8	100.00%	74.58%	0.00%	16.36%	6.01%	3.04%	0.00%
Accumulated Depreciation	F-8	3,114,307	2,322,725	0	509,574	187,321	94,687	0
Net Utility Plant In Service		$12,519,519	$9,337,358	$0	$2,048,489	$753,030	$380,642	$0
CWIP	F-8	$0	$0	$0	$0	$0	$0	$0
M & S Inventories	F-3	$156,540	$156,540					
CIAC & AIAC	F-8	$1,505,198	$1,122,613	$0	$246,286	$90,535	$45,764	$0
Customer Deposits	F-7	$82,563						$82,563
Deferred Income Taxes	F-8	$679,121	$506,505	$0	$111,120	$40,848	$20,648	$0
Remodeling of New Building	F-8	$185,650	$138,462	$0	$30,377	$11,167	$5,644	$0

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

FUNCT. OF OPERATING EXPENSES

DESCRIPTION	FACTOR	TOTAL	DEMAND	COMMOD.	SERVICES	METERS	MTR. INST.	CUST.
Purchased Gas Cost	F-2	1,948,427		1,948,427				
Operations:								
Operating Supervision & Labor	F-3	119,123	119,123					0
Vaporizer Expenses	F-1	0	0					
Mains & Services Expenses	F-3	11,060	11,060					0
Other Operating Expenses	F-3	1,554	1,554					0
Total Operations Expense		131,737	131,737	0	0	0	0	0
Maintenance:								
Maint. Supervision & Eng.	F-3	50,730	50,730					0
Maint. of Structures & Imp.	F-3	13,711	13,711					0
Maint. of Mains	F-3	7,405	7,405					0
Maint. of Vaporizer	F-1	44	44					
Maint. of Measuring Equip.	F-3	0	0					0
Maint. of Services	F-4	3,241			3,241			
Maint. of Meters & Regulators	F-5	3				3		
Maint. of Other Equip.	F-3	28,027	28,027					0
Total Maintenance Expense		103,161	99,917	0	3,241	3	0	0
Customer Accounting:								
Customer Accounting Payroll		94,324						
Customer Records Expense		5,449						
Uncollectible Accounts		-371						
Misc. Cust. Acct. Expenses		6,973						
Total Customer Acct. Expense	F-7	106,375						106,375
Customer Service:								
Customer Service Expense	F-7	33,232						33,232
Sales Promotion Expense:								
Promotion Payroll		26,041						
Advertising Expenses		22,635						
Misc. Sales Expenses		3,215						
Total Sales Promotion Expense	F-2	51,891		51,891				

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

FUNCT. OF OPERATING EXPENSES

DESCRIPTION	FACTOR	TOTAL	DEMAND	COMMOD.	SERVICES	METERS	MTR. INST.	CUST.
Administrative & General Expenses:								
Admin. & General Salaries		200,730						
Office Supplies & Expense		17,761						
Professional Services		140,236						
Property & Liability Insurance		24,855						
Employee Benefits		117,133						
Other Administrative Supplies		4,292						
General Advertising		225						
Misc. Admin & General		39,080						
Rent Expense		29,811						
Maint. of General Plant		2						
Telephone Expense		29,362						
Other Utilities Expense		7,206						
Transportation Expense		21,266						
Travel & Entertainment		12,432						
Business Meals		5,903						
Taxes & Licenses		0						
Postage Expense		20,670						
Total Administrative & General Exp	F-9	670,964	254,986	197,907	0	0	0	218,071
Depreciation	F-8	571,076	425,922	0	93,442	34,349	17,363	0
Property Taxes	F-8	225,657	168,300	0	36,923	13,573	6,861	0
Other Taxes	F-9	6,606	2,510	1,949	0	0	0	2,147
Corporate Exp. Allocation	F-9	24,272	9,224	7,159	0	0	0	7,889
Total Operating Exp. Ex. Inc.Txes		3,873,398	1,092,597	2,207,333	133,605	47,925	24,224	367,713
Functionalization of S & W:								
Operations	F-1/F-3	119,123	59,562	59,562				0
Maintenance	F-3	50,730	50,730					0
Customer Accounting	F-7	94,324						94,324
Sales Promotion	F-2	26,041		26,041				
Total		290,218	110,292	85,603	0	0	0	94,324
Percent	F-9	100.00%	38.00%	29.50%	0.00%	0.00%	0.00%	32.50%

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

FUNCT. FACTOR	DESCRIPTION	TOTAL	DEMAND	COMMOD.	WEIGHTED SERVICES	WEIGHTED METERS	WEIGHTED MTR. INSTA	CUST.
F-1	Demand	100.00%	100.00%					
F-2	Commodity	100.00%		100.00%				
F-3	Distribution Mains	100.00%	100.00%					
F-4	Services	100.00%			100.00%			
F-5	Meters & Regulators	100.00%				100.00%		
F-6	Meter Installations	100.00%					100.00%	
F-7	Customer Accounts	100.00%						100.00%

DERIVED FUNCT. FCTRS	DESCRIPTION							
F-8	Gross Plant in Service	100.00%	74.58%	0.00%	16.36%	6.01%	3.04%	0.00%
F-9	Salaries & Wages	100.00%	38.00%	29.50%	0.00%	0.00%	0.00%	32.50%

CLASS ALLOC. FACTORS	DESCRIPTION	TOTAL	CUSTOMER CLASS RESID.	COMM.
D-1	Winter Peak Demand	100.000%	79.919%	20.081%
CM-1	Commodity	100.000%	77.199%	22.801%
C-1	Services	100.000%	95.523%	4.477%
C-2	Meters & Regulators	100.000%	68.127%	31.873%
C-3	Meter Installations	100.000%	95.990%	4.010%
C-4	Customer Accounts	100.000%	96.946%	3.054%

ALLOCATION FACTORS - BMG DIVISION OF NSP - CC OPERATION

ALLOCATOR D-1 DESCRIPTION	TOTAL	RESID.	COMM.
December 98 Sales - Therms	671,783	522,596	149,187
January 99 Sales - Therms	757,384	618,125	139,259
February 99 Sales - Therms	673,436	539,658	133,778
Total Winter Demand	2,102,604	1,680,380	422,224
Percent	100.00%	79.92%	20.08%

ALLOCATOR CM-1 DESCRIPTION	TOTAL	RESID.	COMM.
Total Sales - Therms	5,224,909	4,033,583	1,191,326
Percent	100.00%	77.20%	22.80%

ALLOCATOR C-1 DESCRIPTION	TOTAL	RESID.	COMM.
Service Installation Cost		$179	$266
Customer Bills - Adjusted	69,985	67,848	2,137
Weighted Cost	$12,713,977	$12,144,792	$569,185
Percent	100.00%	95.52%	4.48%

ALLOCATOR C-2 DESCRIPTION	TOTAL	RESID.	COMM.
Meter Cost		$69	$1,025
Customer Bills - Adjusted	69,985	67,848	2,137
Weighted Cost	6,871,757	4,681,512	2,190,245
Percent	100.00%	68.13%	31.87%

ALLOCATOR C-3 DESCRIPTION	TOTAL	RESID.	COMM.
Meter Installation Cost		$115	$153
Customer Bills	69,985	67,848	2,137
Weighted Cost	8,128,497	7,802,520	325,977
Percent	100.00%	95.99%	4.01%

ALLOCATOR C-4 DESCRIPTION	TOTAL	RESID.	COMM.
Customer Bills	69,985	67,848	2,137
Percent	100.00%	96.95%	3.05%

ALLOCATOR D-1 - DETAIL DESCRIPTION	TOTAL	TOTAL RESID.	REG RESID.	GAS AIR COND.	TOTAL COMM.	COMM.	RESORT	CO-GEN
December 98 Sales - Therms	637,297	488,110	488,110	0	149,187	104,211	34,613	10,363
January 99 Sales - Therms	716,594	577,335	577,335	0	139,259	97,029	35,016	7,214
February 99 Sales - Therms	637,824	504,046	504,046	0	133,778	93,110	30,081	10,587
Total Winter Demand	1,991,715	1,569,491	1,569,491	0	422,224	294,350	99,710	28,164
Pro Forma Adj - Y/E Cust:								
December 98 Sales - Therms	34,486	34,486	34,486					
January 99 Sales - Therms	40,790	40,790	40,790					
February 99 Sales - Therms	35,612	35,612	35,612					
Total Winter Demand	110,889	110,889	110,889	0	0	0	0	0
Adjusted Winter Sales:								
December 98 Sales - Therms	671,783	522,596	522,596	0	149,187	104,211	34,613	10,363
January 99 Sales - Therms	757,384	618,125	618,125	0	139,259	97,029	35,016	7,214
February 99 Sales - Therms	673,436	539,658	539,658	0	133,778	93,110	30,081	10,587
	2,102,604	1,680,380	1,680,380	0	422,224	294,350	99,710	28,164
Percent	100.00%	79.92%	79.92%	0.00%	20.08%	14.00%	4.74%	1.34%

ALLOCATOR CM-1 - DETAIL DESCRIPTION	TOTAL	TOTAL RESID.	REG RESID.	GAS AIR COND.	TOTAL COMM.	COMM.	RESORT	CO-GEN
Actual Sales - Therms	4,954,189	3,762,863	3,756,591	6,272	1,191,326	792,742	298,408	100,176
Pro Forma Adj - Y/E Cust.	270,720	270,720	270,720	0	0	0	0	0
Adjusted Sales - Therms	5,224,909	4,033,583	4,027,311	6,272	1,191,326	792,742	298,408	100,176
Percent	100.00%	77.20%	77.08%	0.12%	22.80%	15.17%	5.71%	1.92%

ALLOCATOR C-1 - DETAIL DESCRIPTION	TOTAL	TOTAL RESID.	REG RESID.	GAS AIR COND.	TOTAL COMM.	COMM.	RESORT	CO-GEN
Service Installation Cost			$179	$179		$230	$469	$469
Customer Bills - Adjusted	69,985	67,848	67,836	12	2,137	1,812	301	24
Weighted Cost	$12,713,977	$12,144,792	$12,142,644	$2,148	$569,185	$416,760	$141,169	$11,256
Percent	100.00%	95.52%			4.48%			
Weighted Cost Per Service			$179		$266			

ALLOCATOR C-2 - DETAIL DESCRIPTION	TOTAL	TOTAL RESID.	REG RESID.	GAS AIR COND.	TOTAL COMM.	COMM.	RESORT	CO-GEN
Meter Cost			$69	$69		$560	$3,617	$3,617
Customer Bills - Adjusted	69,985	67,848	67,836	12	2,137	1,812	301	24
Weighted Cost	$6,871,757	$4,681,512	$4,680,684	$828	$2,190,245	$1,014,720	$1,088,717	$86,808
Percent	100.00%	68.13%			31.87%			
Weighted Cost Per Service			$69		$1,025			

ALLOCATOR C-3 - DETAIL DESCRIPTION	TOTAL	TOTAL RESID.	REG RESID.	GAS AIR COND.	TOTAL COMM.	COMM.	RESORT	CO-GEN
Meter Installation Cost			$115	$115		$146	$189	$189
Customer Bills - Adjusted	69,985	67,848	67,836	12	2,137	1,812	301	24
Weighted Cost	$8,128,497	$7,802,520	$7,801,140	$1,380	$325,977	$264,552	$56,889	$4,536
Percent	100.00%	95.99%			4.01%			
Weighted Cost Per Service			$115		$153			