- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of MOUNTAIN FUEL SUPPLY COMPANY

DOCKET NO. 89-057-15

REPORT AND ORDER

ISSUED: November 21, 1990

1989 TEST PERIOD RATE CASE

SYNOPSIS

By this Order the Commission has established a revenue requirement for the Company of $139,533,000 and an allowed overall rate of return of 12.1 percent.

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APPEARANCES:

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I. PROCEDURAL HISTORY

The Commission on its own motion and pursuant to Section 54-4-2 and other applicable statutory provisions determined to commence a formal investigation into the reasonableness of the rates and charges of Mountain Fuel Supply Company ("Mountain Fuel" or "Company"). A notice of prehearing was issued on October 31, 1989, in which the Commission indicated that the issues of (1) rate of return, (2) affiliate relationships, and (3) cost of service were to be addressed. The prehearing was held on November 7, 1989.

On November 21, 1989, the Commission bench-ordered that a 1989 historical test year would be employed. In response to a Mountain Fuel motion, and following a hearing on the subject, the Commission issued a Protective Order on January 31, 1990.

On January 22, 1990, the Division filed a motion to consolidate Dockets 90-057-02 (gas cost proceeding) and 89-057-15 (general rate case). The motion was granted.

Mountain Fuel filed an application for a general rate increase in the amount of $9,682,000, on March 30, 1990. The Commission set the application for prehearing on April 10, 1990, and, at the prehearing, determined a schedule for the proceedings. This schedule was subsequently amended owing to motions filed by the Division of Public Utilities ("Division") and the Committee of Consumer Services ("Committee"). In one instance the Committee requested clarification about a Commission-directed inquiry of the Wexpro Agreement. In another, the Division alleged failure of the Company to comply with the timetable for response to discovery requests. Sanctions were demanded by the Division.

On June 27, 1990, the Commission issued a formal order denying the Division's request that the Company be sanctioned for failure to meet discovery requirements and granting a request of the parties that a new schedule be set for the case.

On August 27, 1990, the Commission sent a memorandum to the parties notifying them that the issue of the appropriate test-year rate base would be the first item addressed in the hearings.

In addition, the Commission directed the parties to prepare a joint exhibit of their respective positions on the rate case issues.

Hearings began on September 5, 1990. The Committee, on September 17, 1990, filed a motion to compel the Company to respond to a data request and to impose sanctions. The Commission again declined to impose sanctions but directed Mountain Fuel to respond to the data request. On September 27, 1990, following the conclusion of the hearings, the parties filed the required joint exhibit. Thereafter, the parties filed briefs explaining and defending their respective positions.

II. DISCUSSION AND FINDINGS WITH RESPECT TO DETERMINATION OF REVENUE REQUIREMENT

Early in this docket formulation of the test period emerged as a key issue. We had ordered the use of a 1989 historic test year after having considered the parties' arguments, pro and con. Our principal reason for this choice was to avoid bogging down in debates about the adequacy of future test year forecasting techniques at the very time we were endeavoring to learn the actual circumstances of a utility we had not thoroughly examined for some years.

The last Mountain Fuel rate case was concluded in 1985. Since then, several rate decreases have occurred as a result of decreases in gas costs. In addition, the Company found no reason to seek rate relief. We attribute this, in part, to be a result of the quality management of the Company. Our analysis of the principal argument in favor of a future test year, the adverse impact of inflation, convinced us that it was not persuasive at this time. Implicitly, therefore, we did not recognize the need for attrition adjustments.

Thus, use of a historic test year in this proceeding is important in part because of the unusually and undesirably long time that has passed since our last rate case examination of this utility. Actual, historical data has the advantages of simplicity and accountability. In general, such data can be used for rate case analysis, thereby minimizing the use of forecasted data derived by technical and debatable methods.

Prior to this rate case we adopted a rule prescribing test year annualization guidelines. It did not contemplate historic test years and, as the evidence on this record shows, is not readily applicable to them. A future test year embodies forecasted revenues, expenses, and investment; that is, forecasts of changes in both prices and quantities of inputs and outputs. The annualization rule attempts to confine ad hoc test year adjustments to those th[illegible]e not linked, logically and economically, with other revenues, expenses, or investments; those, in the words of the rule, where interdependencies are minimal. This generally means that price, as distinct from volume or quantity, changes may be acceptable. An increase in the price of postage stamps occurring during the test year is one example: in the short term, it may affect nothing else, such as the volume of mailings. However, the price increase is beyond management's control, and failure to account for it may unfairly decrease the opportunity to earn a fair return. Yet, revenues, expenses, and investments must be matched in the test period, or, in other words, revenues and expenses must correspond to investments and accounting information must reflect the underlying economic relationships between inputs and outputs. One ad hoc change which affects other things, without compensating adjustments, will upset the necessary balance. In the interest of proper matching, it should be done as little as possible.

Post-test-year adjustments are not the subject of the annualization guidelines. The Company, and to a limited extent the Division, attempted to apply them to such adjustments in this docket nonetheless. We reject this because the greater the time between the test year and a proposed single item adjustment, the more likely it will necessitate other deliberate changes if test year revenues, expenses, and investment are to remain matched. Even more importantly, with the passage of time prudent management will have adapted operations to any such change in ways not embodied in test-year information and not on this record.

The accounting information presented in this docket generally does not permit us to draw inferences about the utility's economic relationships, that is, how it organizes, in cost minimizing fashion, productive inputs in order to deliver its services. We do not know, for example, what prudent management would do in reaction to or in anticipation of a change in the price of a key input such as labor wage rates. Certainly there is no justification for an assumption that there are no consequences, yet this is what it means to say that a future price level change has minimal interdependencies.

In our opinion, to permit out-of-period adjustments is almost certainly to upset the test-year match of revenues, expenses, and investment. On the other hand, to ignore the change m- impose a risk of under-recovery. When the period between rate c es is short this risk is lessened, as is the potential for mismatch when, as is the case here, accounting data is used to approximate complex economic interrelationships. But when this period is as long as it has been, out-of-period adjustments should be based upon an economic model of the firm. Without the understanding of economic relationships such a model provides, the use of accounting data will tend to support selective adjustments to the test year that are one-sided, and generally proposed by those having information and expertise. This will lead to an undesirable mismatch of investment, revenue, and expenses, generally increasing revenue requirement. Selective adjustments, in short, may yield a less representative test period for ratemaking purposes than no adjustments at all.

The purpose of a test year, or test period, is to provide revenue, expense, and investment information that reasonably approximates circumstances expected during the period rates will be in effect. The rates we set in this docket will be in effect in 1991. Are post-test-period adjustments required to approximate future circumstances? The Company, and in part the Division, say yes; the Committee, no. The Company argued that post-test-year adjustments must be made; the Division, that such adjustments can, with difficulty, be made; and the Committee, that such adjustments create more problems than they solve. According to the Division, the best solution is to move the test period forward in time, nearer to the period rates will be in effect. This cannot be done in this docket. First, we have ordered a 1989 test year, parties have relied on it, and the hearing is over. Second, the Division has not audited 1990 data and no party other than the Company is in a position to present a case based on it.

There are three options. First, we can reopen the record and redo the case based on a test period nearer in time. This is completely impractical and we reject it. Second, we can permit selective out-of-period adjustments loosely corresponding to the guidelines contained in an inapplicable rule. For reasons discussed at length above, we also reject this approach. Third, we can stay with the 1989 test year, permitting in-period adjustments only. We find that this is the most practical and least complex alternative. Upon issuance of this order, the Company or any other party is immediately free, as is always the case, to petition for a change in rates should a party claim a change is necessary.

Confusion and unnecessary work have resulted because the Commission did not decide all of the test-year issues at the outset of this docket. In future proceedings, the Commission will decide issues concerning test year, rate base, out-of-period adjustments, and related matters, prior to the onset of hearings and based on the then existing conditions of the utility and the economy in which it is operating.

A. Average-of-Year Versus End-of-Year Adjustments

1. Average Rate Base

Certain annualization adjustments depend on the choice of average or year-end rate base. The Company argued that, for a historic test year, an end-of-year rate base more accurately reflects conditions expected when new rates will be in effect than would an average-of-year rate base. Essentially, end-of-year rate base is six months nearer in time. The Division agreed, though under questioning from the Commission, its witness, citing the complexity of adjustments to test-year revenues and expenses nece- -ted by end-of-year rate base, stated a preference for using -of-year rate base. The Committee recommended use of average-o rate base based upon consistency with prior Commission ru. and more accurate matching of known test-year investment, revenues, and expenses. According to the Committee, end-of-year rate base, a single point in time, requires that numerous complicated adjustments be made to revenues and expenses to restore a proper matching.

The Commission finds an average rate base appropriate for the following reasons. First, the Commission has relied on average rate base in recent U S WEST Communications and Utah Power and Light dockets. The present docket has produced no compelling reason to depart from that practice. Second, an average-of-year rate base pro- an appropriate basis for matching the annual flows and expenses to the average annual stock of plant and e-----ment employed by the utility and to the manner in which the utility has been operated. An end-of-year rate base is a mere snapshot, a potentially misleading picture of rate base at one point in time. Third, an end-of-year rate base requires that substantial, difficult adjustments, fraught with policy implications, be made to revenues and expenses. Because the Company's application reflects end-of-year rate base, our acceptance of the

Committee's recommendations for average-of-year rate base decreases rate base by $9,542,000.[1]

2. End-of-Year Depreciation

The Company proposed to increase 1989 depreciation expense to reflect end-of-year rate base. Our decision to employ average-of-year rate base in this docket makes this proposed adjustment moot. We find that no expense adjustment is necessary.

3. GS Customer and Use Per Customer Annualization

The Company based its test year on year-end rate base figures, but did not annualize either the number of GS-1 and GSS customers or the customer use based on its position that the product of total customers times customer use or total gas volume delivered has remained relatively constant over the last decade.

The Division recommended that the number of customers should be annualized to match the year-end rate base, but that the usage per customer, which has declined over the last decade, should not be annualized because it had leveled out over the last two heating seasons. The Division annualization adjustment would increase revenue by $2,097,000.

The Company countered that if the Division's annualization of the number of customers was adopted, it would be necessary to annualize the customer usage which the Company views as continu-

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[1] The dollar value of this adjustment is the change in rate base our decision requires. Likewise, our following revenue and expense decisions are expressed as the dollar adjustments required. None of the adjustments are stated in revenue requirement terms until summarized as such in section II.F.

ing the declining trend exhibited over the last decade. The combined effect of the annualization of the number of customers and the usage per customer would be a decrease in revenue of $1,057,000 according to the Company.

The Committee took the position that the average test year approach produces the desired matching of investment, revenues, and expenses and therefore recommended against both adjustments.

The Commission, having adopted the average test year approach, finds the Committee's position appropriate, and rejects both adjustments.

B. Post-Test Period Adjustments

Eight post-test-year adjustments were proposed, all but one of them by the Company. Two of these, the "ET-2" and "customer X" adjustments, though partially offsetting, would increase revenues. Six of them would increase expenses: 1990 labor adjustment, pension plan adjustment, Questar Service 1990 adjustment, production-related depreciation, FICA tax, and gross receipts tax. The effect of accepting them all would be a small increase in test period revenues and a much larger increase in test period expenses. With one minor exception the Committee recommended rejecting the adjustments.

The Division proposed and supported one revenue adjustment and recommended rejecting the one proposed by the Company. The six expense adjustments were proposed by the Company. The Division recommended rejecting two of them and supported, but disputed the dollar amounts of, the remaining four. We will not repeat here the details of party positions any further, having previously discussed our position on post-test-year adjustments under the circumstances of this docket. For the reasons stated in that discussion, we find that the adjustments must be rejected.

The Company included revenues from deferred main extension payments made by a customer added to its system in 1990. The payments are part of a five-year contract. The Company maintained that these deferred payments are a known and measurable benefit to the customers, have no interdependency and should not be eliminated. The Division took no position. The Committee, however, argued that such revenues should not be considered since they occur beyond the test year and recommended an adjustment removing such revenues. The Commission agrees with the Committee and finds that the Company's Utah non-gas revenues should be decreased by $312,000.

C. Test Period Adjustments

1. Adjustments to Industrial Revenues

The Company proposed 75 adjustments to the revenues received from industrial customers, 69 of which primarily involved rate schedule changes and occurred within the test year. The remainder were post-test year. The Company and the Division testified that these are appropriate. The Committee opposed them. There is little basis on this record by which in-period annualization adjustments can be clearly distinguished from post-test year ones. Therefore, the Commission finds that the annualization adjustments are acceptable, and will permit a $72,000 increase in revenues.

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2. Promotional Advertising

The Company testified that $309,000 in test-year promotional advertising expense should be recovered in rates because, it was asserted, the advertising had resulted in increased revenues well in excess of the expense. In the Company's view, this was a ratepayer benefit. The Division and the Committee both argued that the Company had asserted but failed to demonstrate a causal connection between promotional advertising and additional revenues, and in no other way had suggested a benefit sufficient to permit recovery of the expenses in rates. The Commission notes that R750-406-1 prohibits recovery of promotional advertising expenses from ratepayers, unless, under subsection C of that rule, it finds such advertising to be in the public interest. In this instance, the Company has sought to equate what it characterizes as the ratepayer benefit of speculative increased revenues with the public interest. This is not sufficient.

The Commission finds that the Company has failed to demonstrate that its promotional advertising is in the public interest sufficiently to qualify for a subsection C exemption from the R750-406 prohibition and will therefore reduce the Company's expenses by $309,000.

We further find that the Company did not demonstrate that its promotional advertising produced the additional revenues it alleged. Disallowance of these expenses, therefore, necessitates no change in revenues.

3. 1989 Labor Annualization

Mountain Fuel sought an adjustment in the amount of $1,027,000 to bring labor and labor overhead costs to year-end 1989 levels. The Company argued that this adjustment is known and measurable, clearly meets annualization criteria, and is necessary to accurately reflect conditions expected during the period new rates will be in effect. The Division agreed with this adjustment. While not opposed to the adjustment per se, the Committee recommended that the adjustment should be $799,000. The Company argued that the Committee failed to consider the effect annualizing wages to December levels has on overtime pay, on-call pay, and stock plan benefits, among other things. The Commission finds that this Company-proposed adjustment is appropriate and that it results in an increase of test year expenses of $1,027,000.

4. Questar Corporation/Massachusetts Formula

The Company allocated unassigned general corporate costs to Questar Corporation subsidiaries using a three-factor "Massachusetts formula" which assigns equal weight to relative levels of gross plant, labor and gross revenues. The Division recommended that the net revenue version of the Massachussetts formula, established by the FERC in Order 291, be employed in this docket in order to remove gas costs from the revenues of Mountain Fuel and other subsidiaries, thus eliminating a duplication arising from the pass-through of gas costs. The Division argued that Order 291 was not case specific, but was applicable generally. The Committee recommended use of a general allocation factor of 40.46 percent based on gross plant and revenues without gas costs to prevent general corporate overhead costs from being overallocated to the Company. The Commission finds that the gross revenues formula over-allocates general corporate costs to the Company, that the net revenue formula is a better means of allocating such costs, and, accordingly, will adopt the Division's position, resulting in a $575,000 decrease in expenses.

5. Questar Services 1989 True-Up

Mountain Fuel sought an adjustment of $40,000 to reflect the January, 1990 adjustment of test-year Questar Service Corporation charges. The Company argued that the adjustment is necessary to correct a mistake in the December, 1989 billing. The Division did not oppose the adjustment. The Committee argued that the adjustment should be treated consistently with past January true-ups for Mountain Fuel and disallowed. The Commission finds the adjustment acceptable and will allow the $40,000 increase in expenses.

6. Interest Synchronization

The Committee proposed an interest synchronization adjustment to provide equal treatment to customers of Option 1 and Option 2 utilities. The Committee alleged that failure to adopt the adjustment for Option 1 utilities (such as Mountain Fuel) would result in a higher revenue requirement for the Company and rate discrimination against Option 1 ratepayers.

The Company argued that it will violate federal law if it applies interest synchronization and will thereby risk tax penalties. In addition, the ratepayers will risk having the amount of the forfeited tax credits added to rate base. The Division likewise rejected the adoption of the interest synchronization method arguing that it applies only to IRS Code Section 46(f)(2) companies while Mountain Fuel is a 46(f)(1) company. Adoption of the adjustment would penalize the Company at the same time its revenue requirement is already lower than a 46(f)(2) counterpart entity.

The Commission finds that the interest synchronization method proposed by the Committee is not applicable to Mountain Fuel and, therefore, rejects the proposed adjustment.

7. South Georgia Amortization

Mountain Fuel proposed to use the South Georgia method to reflect flow-back of underdeferred tax expenses. The Company argued that this method is consistent with IRS regulations and results in the lowest impact on rates. The Division agreed that this method is appropriate and testified that the Company could lose a $45,000,000 adjustment to rate base if it is not allowed to use this method. The Committee testified that the South Georgia adjustment increases revenue requirement, is not required by the Internal Revenue Code, is merely one method used by FERC for certain utilities, and should be rejected because the Company has not demonstrated that it is required.

The Commission finds that the South Georgia method is appropriate and will allow the resulting $921,000 increase in expenses.

8. **Environmental Clean-Up**

The Company sought to include in this case certain environmental cleanup expenses incurred at its Salt Lake North Operation Center. The Company argued that such cleanup expenses are appropriately recovered in rates because they are normal, ongoing expenses of the Company. The Division agreed with the position of the Company. The Committee, however, argued that such costs are extraordinary, non-recurring and not a normal part of utility operations. The Committee pointed out that these cleanup costs relate to contamination caused from 1908 to 1929 by Utah Gas & Coke Company's coal gasification activities, and, therefore, relate to prior service periods and prior customers. The Committee suggested that to allow such costs today would be a violation of the rule against retroactive ratemaking.

In our Order in Case No. 84-057-07, we said that the failure of the Company to recover certain expenses in the cost of service constitutes a risk of conducting utility business for which the utility is compensated when a rate of return is established for invested capital. However, we are cognizant of the fact that this cleanup was necessitated by government regulation enacted long after the events causing the contamination. We consider that such burdens may be placed upon the Company by government's changing environmental views from time to time and believe that in this instance it is an unavoidable expense for an energy utility. Therefore, the recommendation of the Committee to disallow these expenses is rejected.

9. Brewery Property

The Division proposed a rate base and depreciation expense adjustment for that portion of an acquired piece of property, called the Brewery property, which was in excess of what the Division testified was its fair and reasonable value. The Committee supported the Division's proposed adjustment, modified to reflect an average rather than year-end rate base.

The Company obtained this property through an exchange of other properties involving a Questar Corporation affiliate company, Interstate Land Corporation ("ILC"). Mountain Fuel received the Brewery property along with a garage facility which had been constructed by ILC for the Company. ILC received five pieces of property which were either owned or purchased by Mountain Fuel. The Company proposed that the transaction be evaluated by considering the land priced at market value and the garage and related facilities at depreciated book value. The Company argued that the latter was justified owing to the specific purpose of the facilities and their construction for the Company's utility operation. In addition, the Company proposed that the valuation of its Sunnyside property, one of the five exchanged in payment for the Brewery property, should reflect the Company appraiser's revised assumption of 30 condominium units per acre, decreasing its value in the transaction.

Both the Division and the Committee argued that the valuation of the Brewery property was too high, while that of the Company's Sunnyside property, given an exchange for the Brewery property, was too low. According to them, the key to the exchange is the fact that it occurred between affiliates and was not arms-length. The Division offered an adjustment that valued the transaction at the average of the original appraisals performed by the Company and ILC. It further justified the Brewery property and improvements average appraisal by calculating the depreciated book value of this asset transferred from the affiliate to the utility and arriving at essentially the same value.

The Commission is of the view that transactions involving affiliates place ratepayers at a disadvantage that can never be entirely controlled or offset. For that reason it is generally appropriate to allow transfers of property from affiliates to the utility at the lesser of book or market and transfers going the other way at the greater of book or market. We find that Mountain Fuel's property transferred to an affiliate should be valued at the greater of market or book, while that transferred from an affiliate to Mountain Fuel should be valued at the lesser of market or book. We further find reasonable the Company's proposed valuation of the Sunnyside property on the basis of 30 condominium units per acre. Therefore we will accept the Division's adjustment as modified by the Sunnyside changes. These decisions result in two adjustments, a decrease in depreciation expenses of $23,000 and a decrease in rate base of $923,000. We would note that if the Company had sought Commission approval of these affiliate transactions at the time they took place, which approval is required under our 1984 Order approving the reorganization of Questar Corporation, Docket No. 84-057-10, it would have been in a better position to justify its actions and/or provide additional data where its position was inadequately supported.

10. Affiliate Rate of Return

All parties agreed that affiliate transactions involving Mountain Fuel should be based on this Commission's authorized rate of return on equity. Having determined in this docket that the rate of return on equity allowed is 12.1 percent, the Commission therefore finds that an adjustment to expenses of $42,000 is appropriate.

11. Affiliate Transaction Disallowances

The Committee recommended that the Commission impose a disallowance of not less than 10 percent of the 1989 test-year affiliated transaction charges billed by Questar Corporation and Questar Services Corporation to Mountain Fuel. The Committee based this recommendation on the Commission's Order in the U S WEST Communications, Inc. case, Docket No. 88-049-07, in which it was determined that the Company has the burden to justify its affiliate transactions. The Committee argued that Mountain Fuel had failed to meet this burden. The Division opposed the penalty and testified that, based upon its extensive audit review, there was not evidence that the transaction charges were inappropriate. The Division also stated that the Company had readily provided requested information about its affiliate transactions.

Were it not for the testimony of the Division, we would conclude that the Company's affiliate transactions had not been justified on this record. Regulatory oversight, however well performed by the Division, will not displace utility management's responsibility to meet its burden in future proceedings. We find that the Division has met the Company's burden and therefore reject the disallowance recommended by the Committee. We also find that the burden to justify affiliate transactions is, and must always be, the utility's.

D. Cash Working Capital

1. Lead/Lag Study Results

The basis of the cash working capital requirement is the Company's lead/lag study. The study contains ten broad categories of revenues and expenses, and each category is associated with lead/lag day. The study calculates a net composite lead/lag day as an average of the individual lead/lag days weighted by the dollar amount in each respective category. An average daily cash working capital requirement is obtained as the product of the net composite lead/lag day and cost-of-service, divided by 365 days. There are tw[illegible]uted issues concerning the lead/lag study. The first is the rev[illegible] lag day associated with delinquent accounts and the second is [illegible] expense lead day associated with income tax payments.

a. Delinquent Accounts

The Company testified that the delinquent account balance was an average for the entire year and therefore a revenue lag of 365 days should be employed. The Division took issue with the Company's use of a 365 revenue lag day. The Division testified that due to the lack of quantifiable information caused by the Company's exclusion of delinquent accounts from its statistical sampling method, it is appropriate to use a revenue lag day determined as an average of the number of days the accounts were delinquent weighted by the actual dollar amount of delinquent accounts.

The Committee recommended that delinquent accounts be removed from the lead/lag study. The Committee argued that Mountain Fuel's proposal is inconsistent with the treatment requested in its recent Wyoming rate case. In addition, the proposal is deficient in that it fails to accurately measure the impact of delinquent accounts by overlooking offsets such as the customer-contributed capital available from the accumulated provision for uncollectible accounts.

The Commission finds that the analyses of this issue by the Company and the Committee are not satisfactory and that the proposal of the Division is the most reasonable. Therefore a revenue lag of 125.39 days associated with delinquent accounts should be applied in this case.

b. Income Tax Payments

Mountain Fuel proposed an expense lead day associated with income tax payments, computed from actual 1989 historic test year payments. The Division based its factor on statutory due dates and a June 30th test year mid-point. According to the Division, the expense lead day associated with income tax expenses should not be based on actual results which are the product of Company estimates but should be based on a fixed payment schedule throughout the year. The Division argued that the Company's estimates unnecessarily increase cash working capital. The Committee supported the Division's proposal. The Commission finds, consistent with its decisions in prior cases, that it is appropriate to use statutory due dates to determine the expense lead day associated with income tax payments as recommended by the Division and therefore an expense lead of 59.32 days should be applied in this case.

c. Adjusted Lead/Lag Study Results

The Company adjusted its lead/lag study to incorporate Commission findings concerning revenue and expense adjustments and findings with respect to the lead/lag days associated with delinquent accounts and income tax payments. **The Commission finds reasonable the adjusted lead/lag study which results in a cash working capital requirement of $2,824,000.**

2. Compensating Balances

The Company proposed to include in cash working capital the cash balances required to maintain lines of short-term credit and cash funds for other administrative purposes. The Company argued that these cash balances are assets necessary to the operation of the Company and therefore a return on such balances should be allowed. The Division argued that there should be no addition to rate base for compensating balances because investors know that funds are required for administrative purposes and their return on equity expectations already reflect this understanding. The Committee agreed with the Division that compensating cash balances should not be allowed as a component of cash working capital. **The Commission finds, consistent with its decisions in prior cases, that it is not appropriate to include compensating cash balances in the determination of cash working capital and therefore rejects the Company's proposal.**

3. Require Payment in 23 Days

The Division proposed to reduce the Company's cash working capital requirement as a result of its proposal to modify the Company's billing practices by requiring customer payment within 23 days after the billing date. According to the Division this reduction in payment period would produce an annual savings in revenue requirement. The Company argued that the proposed adjustment is not known and measurable and the modification to its billing practices would require the addition of employees and equipment, and would not be favorably perceived by its customers. The Committee testified that the Division's proposal would be appropriate only if the 23-day period was fully reflected throughout the determination of cash working capital. The Commission finds that the proposal is insufficiently developed in this case and will not adopt it at this time. We may revisit this issue after the task force currently addressing these issues submits its report.

E. Rate of Return

1. Rate of Return on Equity

The position the Company took in this docket is that a return on common equity above 13 percent is required by investors. This was the conclusion of its witness, Dr. Williamson, who analyzed a sample of comparable companies primarily by application of a discounted cash flow (DCF) model to a sample of representative gas distribution utilities. He supported this analysis with capital asset pricing model and risk premium tests, and a study of comparable risk using Hope and Bluefield case guidelines. Dr.

Williamson's sample consisted of eight companies which he determined had operational and risk characteristics similar to the Company's. Size, service territory degree-days, proportion of distribution operations, and availability of information were the factors used to select the sample. To estimate expected growth, a key component of the DCF analysis, Dr. Williamson relied on security analysts' estimates of earnings growth rates. Forecasted growth, added to estimated dividend yield, which he based on next year's dividend, and applied to the sample companies, then checked by the Hope and Bluefield and risk premium analyses, yielded the recommendation. In prefiled testimony, Dr. Williamson's estimate of the required return was 13.5 percent. At hearing's end, the Company advocated a return above 13 percent.

Division witness Eatmon recommended a 12.0 percent required return on equity. Mr. Eatmon relied on the DCF method, applying it to several different samples of comparable companies. His estimate of the DCF growth component was based on forecasts of earnings and dividend growth rates, equally weighted. For dividend yield, he selected 12-month average stock prices, after reviewing market prices for periods of one, three, six, and twelve months, and employed an estimate of the next period's expected annual dividend. Application of the DCF model to the comparable companies resulted in an 11.6 to 12.4 percent range of reasonable estimates of investor required returns. Mr. Eatmon recommended 12.0 percent.

The Committee and Nucor Steel jointly sponsored the testimony of Dr. Marcus on these issues. Dr. Marcus's DCF analysis of comparable companies led to his recommendation of 12.2 percent as the cost of equity capital.

These witnesses were in agreement that Mountain Fuel Supply's actual capital structure should be used in this proceeding. Though the Company is a subsidiary of a holding company, each testified that the actual capital structure could be measured in an acceptable manner and would be appropriate to derive the overall cost of capital.

We can only determine the cost of capital indirectly, by assessing expert opinion about the rate of return investors can be expected to require if they are to purchase equity shares. This required market rate of return is hypothetical and is estimable only through a conscientious, fair-minded exercise of judgment.

Our decisions must afford the utility the opportunity to earn a fair rate of return. This is a return which will maintain the utility's credit standing and allow it to attract additional capital, thus assuring its financial integrity. Also, this return would allow it to achieve earnings comparable to companies of similar risk. Such standards guide our decisions and are well known. At the heart of our considerations, however, is the presumption of an efficient, effective management.

The rate of return must not be set so high as to exploit consumers, however. Thus, the concept of a fair rate of return suggests a range or a zone of reasonableness. A return permitted within this range will be just and reasonable; earnings within the range will not be insufficient for the Company or harmful to consumers. We must balance the interests of owners and customers.

On this record, expert witness testimony places the fair rate of return at 12.0, 12.2, or 13.5 percent, estimates drawn from a range, considering the work of all three witnesses, that is somewhat broader. One hundred-fifty basis points separate the three point estimates. Each basis point amounts to $23,000 of revenue requirement.

The evidence shows, and the parties themselves agree, that each witness testified credibly. Widely accepted techniques, though primarily the DCF model, frame their analyses.

The principal value of the DCF or other models presented on the record is the delimitation and organization of relevant information. Sophisticated extension and elaboration of the models is of doubtful value since it can only obscure the subjectivity, the careful Commission judgment, that is the deciding factor. In this case, the presentation of the models has been straightforward, without suggestion of an unrealistic precision.

Our orders in recent rate cases reveal growing reliance on the DCF method. It is :eptable because it is understandable, its basis in theory reasonable, its components estimable in our --ceedings, and perhaps above all, its results reliable under a :iety of circumstances. The same cannot be said of the capital asset pricing model, which in our proceedings seems immersed in doubt. The technique is of questionable reliability and more often th not has been employed to support a rate of return recommenda- -n much higher than indicated by DCF results. As with the risk premium approach, measuring the components is problematical. While the DCF method is not free of problems, including circularity-- regulation authorizes earnings, which influence dividends per share, from which yield is determined and the growth rate is estimated, all then resulting in calculated equity cost--the results of its application by witnesses with differing points of view typically fall within a narrow range and we have been able to assess their disagreements. We therefore reaffirm a previously stated determination to place little reliance on other methods. (See Report and Order, Docket Number 88-049-07, October 18, 1989, pp. 65-67.)

Our first concern is the estimation by the witnesses of the DCF variables and the samples of comparable firms to which the method is applied. Secondly, we will consider other influential factors.

The discounted cash flow method estimates the investor's capitalization or discount rate, the cost of capital, as the sum of the dividend yield and the expected dividend growth rate. Current dividend per share is divided by current market price to obtain dividend yield. There is some disagreement concerning the proper dividend and price to use, but the more significant disputes arise over the estimation of the dividend growth rate.

In theory, the DCF model requires a dividend yield calculated for the point in time that cost of capital is determined, that is, current annual dividend divided by current market price. Short-term fluctuations in market price can affect the cost of capital determination unduly, however, so each witness used a price averaged over a period of time determined to be representative. The dividend used was adjusted to reflect the next period's expected annual dividend by each witness, but the Committee and the Division witnesses both criticized Dr. Williamson's next period yield adjustment as unsupportably high.

The estimation of a dividend growth rate is problematical and can be contentious. In this docket, Company witness Williamson used earnings growth rate forecasts as the basis for his dividend growth rate estimate. He described DCF as working best "when both earnings and dividends are in a smooth upward trend and when forecasts of growth are consistent," and asserted this was true for his sample of eight companies. Both Committee and Division witnesses criticized his approach. Dr. Marcus analyzed historic growth patterns, growth in retained earnings, and reviewed analysts' opinions in his effort to estimate expected dividend growth rates. He asserted that Dr. Williamson had been unduly influenced by analysts' opinions and had not analyzed historic growth behavior. Moreover, two firms in the Williamson sample of eight show unrealistically high growth rates, 22 percent for one and 15 percent for the other. Division witness Eatmon estimated a dividend growth rate based on both earnings and dividend growth forecasts. He testified that the Company used unrealistic earnings growth projections as the basis for its DCF dividend growth rate. Both Division and Committee witnesses recommended rejecting this aspect of Williamson's DCF analysis, and stated this would bring the Company's DCF result down from 13-14 percent to near 12 percent, virtually the same as they had obtained.

Each witness applied the DCF model to sample companies, but differed as to the correct sample. According to Dr. Marcus, comparable firms are few in number and the use of reasonable measures of risk resulted in a sample that was too small to be useful. He therefore used the Moody's gas distribution group of firms, abandoning a risk analysis. Dr. Williamson employed several measures of risk and comparability to select his eight-company sample. All but one of these measures, size, are met by the

Moody's group, according to Dr. Marcus, and use of the size measure results in a different sample. Dr. Marcus criticized the use of size as a measure and asserted that no systematic relationship between size and risk exists. He also questioned Dr. Williamson's use of degree-days as a risk factor, stating that whether fewer degree-days correlates with lower risk depends upon volatility of weather and a utility's ability to deal with it. Such an analysis was not presented. Division witness Eatmon examined several samples, including one consisting of 'A' rated companies. The Division argued Dr. Williamson's sample did not yield reasonable results, whereas the Division's more encompassing analysis did. The main problem identified with the Williamson sample, according to the Committee, is the inclusion of one company with a DCF cost of capital estimate of 25 percent. It was asserted that a company having a market-required return of 25 percent bears no relation to Mountain Fuel Supply and does not belong in a sample.

We can only accept Dr. Williamson's DCF results in part. The critique offered by the Division and the Committee witnesses is persuasive in three important respects. First, the adjustment to bring the dividend to the next period is excessive. Second, the sample of firms contains at least one company that, arguably, is not comparable, producing an upward bias in the dividend growth rate estimate. And third, reliance upon earnings growth rate forecasts to estimate the dividend growth rate also imparts an upward bias. A cost of equity estimate near those of the other two witnesses is obtained when corresponding adjustments are made. On this basis, we find the cost of equity to be 12.2 percent.

There are reasons why the cost of equity obtained from a model may differ from a fair rate of return allowance. Where we wish to compensate for outstanding management performance, or to provide an incentive for efficiency, or to compensate for extraordinary risk, we can do so by setting a return greater than the minimum cost of equity. The converse of this is also true. We can adjust where we have reason to believe management has not adequately met its ic service obligations.

_e record contains no evidence suggesting that Mountain Fuel Supply Company is either more or less risky than comparable gas distribution companies, and Dr. Williamson so testified. Nor is there any evidence suggesting that the Company suffers from attrition; i.e., the adverse effects of inflation to which management is unable to adjust. The record suggests, though without benefit of systematic examination, that Company management has performed very well in most respects. In two areas, however, affiliate relationships and gas supply planning, we take issue with the management of the Company's parent, Questar Corporation.

The record shows that this company has organized and reorganized during the 1970s and 1980s in order to capitalize on market opportunities, to simplify its relationship with federal and state regulatory entities, to clarify its activities for shareholders, and for other reasons best known to management. In 1984, docket number 84-057-10, we permitted the formation of a holding company structure, with the utility we regulate as a subsidiary. This approval was conditional, however, and the conditions were to ensure that we could continue to regulate the utility in the public interest. Evidence on this record, however, strongly suggests a deliberate shift of risk from Questar Corporation operations generally to the distribution utility and thence to its core customers. Affiliate relationships have constrained and inhibited the pursuit of least-cost gas supply by the distribution utility. Though Questar Pipeline Company's rates and rate structure can adversely affect the distribution utility and its core customers, the utility has never intervened to represent these interests at FERC cases where such rates are determined. We find no convincing evidence of an attempt to simulate an arms-length relationship with Questar Corporation subsidiaries, or better, to deliberately overcome the inherent lack of such a relationship. The chief case in point is the assumption by an affiliated company having interests demonstrably different from the utility's of the utility's gas supply planning, acquisition, and dispatch functions. These issues are all discussed at greater length in Section III, pages 34-43. In our judgment these actions do not protect the interests of the utility's customers. We determine, therefore, to impose an adjustment in the form of a reduction in the allowed rate of return of 10 basis points.

In summary, we find that the utility's cost of equity capital as determined, in the main, by various discounted cast flow analyses, is 12.2 percent. The equity rate of return which we find to be just and reasonable, is 12.1 percent.

2. Capital Structure and Rate of Return on Rate Base

The cost of capital may vary with the debt-equity ratio. For this reason and others, we have at times adopted a hypothetical capital structure which exhibits debt and equity in proportions as suggested by sample companies. This capital structure would insulate utility customers from the potentially adverse effects of subsidiary operations, from management financial decisions that might increase the cost of obtaining capital, and from the problem of measuring an actual capital structure for a utility that is a subsidiary of a holding company. Adoption of a hypothetical capital structure is an adjustment similar to the disallowance of any unreasonable expense. There are, however, arguments to be considered why a hypothetical capital structure should not be adopted.

In the present docket no witness has opened the door to these difficult matters. Each testified that the utility's actual capital structure should be used to determine the overall rate of return. It was also clear on the record that the Company's actual capital struture was within the range of hypothetical capital structures calculated from a reasonable sample of companies. All parties used the same capital structure component weights and costs, with the exception of the cost of equity capital, to derive the overall rate of return recommended. Substituting the cost of equity we have determined to be reasonable, 12.1 percent, produces an overall rate of return of 11.03 percent. We find this rate to be fair, just and reasonable. We will note, however, a concern with the costs of debt and preferred stock in this capital structure, and request the Division to conduct an examination to determine if these costs might be reduced.

F. Revenue Requirement Summary

The following table summarizes the revenue requirement determinations reached in this proceeding. It presents the derivation of a revenue requirement deficiency of $76,000.

SYSTEM COST BY FUNCTION
ADJUSTED TEST YEAR ENDED DECEMBER 1989
MOUNTAIN FUEL SUPPLY COMPANY
($000)

)PERATING EXPENSES (1)	TOTAL RATE BASE (2)	TOTAL COSTS (3)	PRODUCTION (4)	WYOMING (5)	UTAH (6)
.. Operation & Maintenance Expenses		76,297	2,308	3,708	70,281
:. Depreciation, Depletion & Amortization		17,215	3,716	765	12,734
i. Taxes (Excluding Income Taxes)		7,801	113	462	7,226
i. Colorado Credits		(353)	(353)		
i. TOTAL OPERATING EXPENSES		100,960	5,784	4,935	90,241
i. FEDERAL INCOME TAX)istributed on Rate Base Basis)		13,204	2,295	708	10,201
RETURN)stributed on Rate Base Basis)					
'..)uction	52,745	5,818	5,818		
i. Distribution – Wyoming	16,279	1,796		1,796	
i. – Utah	234,462	25,860			25,860
.0. TOTAL RETURN @ 11.03%	303,586	33,474	5,818	1,796	25,860
.1. System Non-Gas Costs		147,638	13,897	7,439	126,302
:2. Utah percent = >			95.21%	0	1
.3. Utah costs = >		139,533	13,231	0	126,302
.4. TOTAL UTAH REV		139,457			
.5. UTAH DEFICIENCY		76			

III. DISCUSSION, FINDINGS, AND CONCLUSIONS WITH RESPECT TO GAS SUPPLY

A. The Gas Supply Function

The Division's consultants, Theodore Barry and Associates ("Barry"), performed a qualitative examination of the management and technical aspects of the gas supply planning and related activities of Mountain Fuel Supply and its affiliates. The Committee's consultants, Exeter Associates ("Exeter"), reviewed the gas supply procurement arrangements of Mountain Fuel for consistency with a least-cost acquisition strategy.

The gas supply function can be segmented into four interrelated areas: load forecasting, design day analysis, gas supply planning, and gas supply dispatch. Mountain Fuel's Forecasting and Load Research Department develops both load forecasts and design day estimates. Beginning with the 1990 planning cycle, Mountain Fuel has stated these forecasts will normally be for ten years.

According to Barry, the management process involved in load forecasting and in formulating the design day estimate appear to be reasonable and consistent with industry practice. Further, Mountain Fuel does do a reasonably good technical job of forecasting the loads of the residential sector. Because the residential sector is its most important load, Barry concluded that it is likely that Mountain Fuel's cost of service is not substantially higher than it would be with better gas load forecasting. In addition, the technical considerations of design day for Mountain Fuel as a distribution utility are rather straightforward such that either the design day issue does not really exist at the Mountain

Fuel level or it is significantly less of a technical issue than it is at Questar Pipeline Company.

Questar Pipeline develops and prepares a gas supply plan for all gas to be delivered to Mountain Fuel under the terms of the Gas Supply, Odorization and Operating Services Agreement between Mountain Fuel and Questar Pipeline. The written policy of Questar Pipeline filed at the Federal Energy Regulatory Commission ("FERC") essentially says that Questar Pipeline will use its best efforts in consideration of all its operating and contractual requirements to provide its jurisdictional customer, Mountain Fuel, with reliable supplies at the lowest achievable cost.

Mountain Fuel has two sources of gas supply, its own production and contract purchases from Questar Pipeline at rates established by the FERC. Mountain Fuel is Questar Pipeline's only sales customer and Questar Pipeline is the only source of contract purchases for Mountain Fuel. Mountain Fuel's own production is operated by WEXPRO, a Questar affiliate, under the terms of the WEXPRO Agreement. For planning purposes, WEXPRO supplies Mountain Fuel with reserve and deliverability estimates of Mountain Fuel's own production. Mountain Fuel determines the quantity of such reserves expected to be produced by WEXPRO during the planning period.

Mountain Fuel supplies its gas load and design day forecasts, along with the desired production from Mountain Fuel's own sources to Questar Pipeline. Questar Pipeline incorporates the Mountain Fuel information with Questar Pipeline data relating to reserves, deliverability, and contractual requirements of purchase gas sources. The latter includes Celsius Energy Corporation

("Celsius"), an exploration and production subsidiary all of whose production is purchased by Questar Pipeline for resale to Mountain Fuel.

Questar Pipeline determines a gas supply plan using an economic optimization model, the Gas Contract Analyzer ("GCA") model. The gas supply plan is returned to Mountain Fuel for review, further modification, and ultimate agreement with Questar Pipeline. Questar Pipeline then implements the plan by means of a non-optimization model, the Gas Dispatch and Cost (GDC) model. Mountain Fuel monitors the implementation of the plan through monthly written reports and review meetings and daily dispatch review meetings.

According to Mountain Fuel, the GCA model is used to develop strategy to deal with uncertainty by undertaking sensitivity studies and analyzing contingencies. Mountain Fuel claimed the model is not well suited for the development of an annual gas supply plan and there is not a focus on one specific GCA result as an optimized solution to be replicated by the GDC model.

Both Barry and Exeter claimed that Questar Pipeline's use of the GCA model did not provide a least-cost gas supply plan, that Mountain Fuel personnel did not possess a technical understanding of the GCA model and its use by Questar Pipeline, and that Mountain Fuel management lacked oversight and control of Questar Pipeline. They also stated that Mountain Fuel's lack of oversight of its pipeline supplier and the fact that it does not purchase either spot or other market gas is relatively unique in the industry.

According to Barry, the gas dispatch performed by Questar Pipeline for Mountain Fuel is quite good in that the dispatch instructions developed by the GDC implement well what the GCA calculates to be the gas supply plan.

Although disputed issues remain among the parties concerning the gas supply planning function, the Commission finds that possible improvements in the load forecasting, the design day estimate, and the gas dispatch functions, while desirable, are unlikely to substantially reduce the annual costs of gas supply.

B. Corporate Organization and Affiliate Relations

The current form of corporate organization reflects the corporate objective of reducing what it views as duplicative regulation, with Mountain Fuel subject to regulation by this Commission, its sister affiliate Questar Pipeline subject to regulation by the FERC, and WEXPRO, unregulated.

Mountain Fuel contracts with Questar Pipeline and WEXPRO are effectively cost-plus contracts. The only oversight Mountain Fuel has of Questar Pipeline is through FERC regulation and two independent monitors provide oversight of WEXPRO.

Mountain Fuel stated that decisions regarding gas supply often involve conflicts between the interests of Mountain Fuel and Questar Pipeline. When such conflicts of interest do arise, they are resolved within Questar Corporation. Since disputes are effectively resolved by the corporate parent, independent arms-length transactions and adversarial relationships cannot be expected to occur among affiliated economic entities.

Mountain Fuel further stated that any major proposal that Questar Pipeline makes at the FERC is the result of internal considerations. Questar Pipeline has a collection of customers only one of which is Mountain Fuel. The proposals it makes at the FERC are the result of internal consensus and attempt to balance the interests of the various entities involved, including the shareholders of Questar Corporation.

Recent Questar Pipeline cost-of-service and rate design issues at the FERC have resulted in a shift of costs from other customers of Questar Pipeline to Mountain Fuel. Mountain Fuel has never participated at FERC in a Questar Pipeline rate proceeding. The Division, not Mountain Fuel, intervenes at FERC on behalf of Mountain Fuel's ratepayers.

Based on the foregoing, the Commission finds that the current organizational structure of Questar Corporation and pattern of regulation provide an opportunity for Mountain Fuel to bear a disproportionate share of the risks facing Questar Corporation and, in particular, for Questar Pipeline to subsidize its activities in other markets by shifting costs to Mountain Fuel. Further, inter-affiliate agreements and regulatory oversight of affiliates are not a substitute for utility management oversight and control.

C. The GCA Gas Planning Model and its Use by Questar Pipeline

The objective of the gas supply plan provided by the GCA model is to minimize the net present value of gas acquisition costs consistent with supply reliability over the planning horizon. The model is limited by a number of operational requirements and constraints, and the forecast information available to the company at the time the plan was prepared. Operational requirements and constraints include the use of Mountain Fuel's own production, must-take purchase contracts with Questar Pipeline, and the use of Questar Pipeline storage.

Mountain Fuel's own production is not subject to optimization within the model but is exogenous to the model. Mountain Fuel stated what it has done is consistent with the stipulation reached with the Division. Mountain Fuel stated that in the future it would like to investigate the modeling of economic optimization of its own production.

Exeter agreed with the testimony of Division witness Darrell Hanson concluding that prices of gas obtained under the WEXPRO Agreement compare favorably with alternative sources. However, Exeter expressed concern that Mountain Fuel has little control over when WEXPRO decides to develop new wells and the supply of gas forthcoming from such wells in relation to Mountain Fuel's demand needs and other supply options.

The GCA models all gas supplies as contracts requiring the aggregation of data describing approximately 1,700 individual wells into 30 contract or well groups for use by the GCA. The data provided to Barry by Questar Pipeline segmented wells on the basis of load factor thus preventing the GCA model from optimizing across well groups with respect to price. Mountain Fuel claimed the data provided to Barry was in the process of being updated for use by a new version of the GCA. No party disputed the need for segmenting well groups on the basis of price as well as load factor.

Originally the GCA model did not treat take-or-pay issues. Mountain Fuel designed a method for modeling take-or-pay in which the objective is to reduce Questar Pipeline's exposure to take-or-pay liabilities. The Mountain Fuel approach provided high take-or-pay penalty rates in order to constrain the model to deal with must-take sources of gas supply, thus passing take-or-pay liabilities of Questar Pipeline on to Mountain Fuel. There is no provision in the GCA model which allows a buy-out or buy-down of take-or-pay liabilities.

Spot market purchases were effectively eliminated as a feasible alternative since, if a unit of spot gas is taken, the full amount of the the take-or-pay liability on the gas that is not taken must be paid in full.

The model constrains the use of storage consistent with FERC-imposed dates that permit Questar Pipeline to take and replace gas from storage. Questar Pipeline provides storage as a part of firm sales or transportation service. Questar Pipeline's storage costs are recovered in FERC firm sales (CD-1) and transportation (T-1) rates. Questar Pipeline does not provide unbundled storage service.

Since Questar Pipeline does not offer unbundled storage, the model does not contain as a feasible alternative Mountain Fuel purchases from independent third parties with Questar Pipeline providing transportation and storage service. The sole source of gas supply to Mountain Fuel beyond its own production is Questar Pipeline. The Kern River and WyCal pipeline proposals are not considered feasible sources of supply due to the low load factor of Mountain Fuel's demand and the need for storage to serve such a low load factor customer. Although FERC determines the timing of storage use and the method by which storage costs are recovered in rates, such determinations can be changed in future FERC proceedings.

Actual historical data was not available to Barry thus preventing Barry from quantifying the effect on gas costs of operating in a manner different from that modeled by Questar Pipeline. Further, no party recommended an adjustment to revenue requirement as a result of analyzing the GCA model and its use by Questar Pipeline.

The Commission finds that the use of the GCA model by Questar Pipeline may not provide a long term least-cost integrated resource plan. The Mountain Fuel contracts with Questar Pipeline and WEXPRO are cost-plus contracts, and are not the result of arms-length transactions but result from a single economic interest. Mountain Fuel's own production and contract purchases from Questar Pipeline are the only sources of gas supply treated in the GCA model. Economic optimization of Mountain Fuel's own production is lacking. The GCA model excludes FERC reconsideration of take-or-pay liabilities or use of storage over the planning horizon. Finally, spot market and independent third party sources are not supply options, and demand side considerations are absent.

D. Conclusions

The Commission finds that the current practice of the gas supply planning and purchase functions residing within Questar Pipeline is not in the public interest.

We recognize that there may be problems with implementing these functions within Mountain Fuel. The current unavailability of unbundled storage and transportation in the tariffs set by FERC for Questar Pipeline is one such problem which comes immediately to mind. Nevertheless, we must begin the process of analyzing and implementing changes in the gas supply planning and purchasing functions.

The Commission has two primary goals in consideration of the gas supply planning function. The first goal is to create a method which duplicates arms-length transactions between Mountain Fuel and the Questar family of companies. The second goal is to design a method, for the long term, to provide the lowest priced gas supply to Mountain Fuel ratepayers without any regard to corporate structure or the needs of the corporate parent or affiliates. In light of these goals, the Commission finds that the gas planning function of Mountain Fuel should be moved from Questar Pipeline to Mountain Fuel.

Two events present an opportunity for Mountain Fuel to be considering what its future options are: 1) take-or-pay liabilities or take requirements that present take-or-pay liabilities come to an end in the 1993-94 timeframe; and 2) complete deregulation of gas occurs in 1993. A review of a long-term least-cost integrated resource plan for Mountain Fuel cannot be made in 1993 when Questar Pipeline has already made commitments to continue to fulfill its function and responsibilities to Mountain Fuel. Therefore the Commission finds that Mountain Fuel is to provide a long-term least-cost integrated resource plan within six months for review by the Commission and other interested parties. Mountain Fuel is to provide the funding necessary, as pre-approved by the Commission, to allow the Division and the Committee to contract with consultants for a management audit follow-up. The Commission will allow inclusion of such funding as an expense in the 191 Account.

The Commission further finds that a task force is to be established to consider the various issues that have arisen in this case. Issues to be considered shall include but need not be limited to the following:

1. How the gas planning function is to be returned to Mountain Fuel;
2. Recommendations of Barry concerning load forecasting, [illegible]n day estimation, and gas supply dispatch;
3. Recommendations of Barry and Exeter concerning the use of the GCA model;
4. Cost/benefit analyses of relaxing model constraints;
5. Possible changes in FERC regulation necessary to increase the feasible options of Mountain Fuel and/or reduce the limitations of constraints including, among other issues, the availability of transportation service, the use of storage, the unbundling of storage service, the possible buy-down of take-or-pay liabilities, and the availability of spot market sources;
6. The investment incentives facing WEXPRO and the resulting economic impact on Mountain Fuel;
7. The maintenance of a historical data base and recommendations for annual review of gas supply decisions; and
8. The relevance and applicability of planning and dispatch models to the development of an annual gas supply plan for ratemaking purposes.

IV. DISCUSSION AND FINDINGS WITH RESPECT TO RATE SPREAD AND RATE DESIGN

A. Stipulated Cost of Service and Rate Design

Cost of service and most rate design issues in this docket were resolved by a stipulation of the parties that we tentatively accepted on September 5, 1990, and finally approve with this order. A copy is appended.

B. Disputed Issues

1. General Service (GS) Rate Design

Three general service rate design proposals were presented which if accepted would alter customer charge and block elements of the rate. Currently, the rate consists of a $5 customer charge and two declining blocks. Division witness Compton proposed to replace the two blocks with three in order to better track intra-class cost-of-service differences tending to harm larger customers. He also proposed a summer/winter differential in GS-1 rates based on seasonal gas cost differences. The Company proposed increasing the customer service charge to $6. The Committee opposed both the Company's $6 customer charge and, testifying on the importance of price signals for conservation, the Division's three-block recommendation, suggesting a flattened two-block structure instead. The Committee also opposed the summer/ winter differential, in part, on grounds that low-income households would be harmed by it.

Our rate design decisions are guided by a number of objectives including efficiency, conservation, equity, stability, and simplicity. We have described these at length in the past and wish to say here only that the objectives may be in conflict at times. Cost-of-service based rates are an important means of attaining equity and efficiency, and, some would argue, conservation as well.

We have no desire to change rates just for the sake of having done it. In this docket, we must change them as to amount; structure is another matter. Rates for general service customers will go up for three reasons: increased commodity costs in the pass-through part of this proceeding (see Report and Order, Docket Nos. 90-057-02, 90-057-07, October 31, 1990); the stipulation redresses an inequity which shifts costs from interruptible transportation customers to general service customers; and a small increase in revenue requirement.

General service rate structure changes have been presented to us as proposals to make rates more closely conform to the costs of providing service, thereby addressing intraclass inequity and sending the proper price signals about seasonal variation in gas costs. These are small changes and not the only way to address the problem. They are also controversial proposals, and have in fact been opposed in this proceeding, including substantial opposition by public witnesses. They raise questions about which ratemaking objectives might be attained and which not. For instance, not all parties define conservation in the same way and, given this, oppose a declining block rate, however much it may be cost-based. Rate stability is also a concern. Simplicity and understandability are also rate design objectives, and both would be confounded by the introduction of an increased customer charge, a three-block declining rate, and a summer/winter differential.

In our judgment, now is not the time to implement these changes. By accepting the stipulation on cost of service and rate design, we have resolved some matters and opened the door to others. We require a dispassionate examination of rate structure, which permits alternatives to be identified and analyzed. **We find that the increase in customer charge, the change from a two-block declining rate, and the summer/winter differential should not be implemented at this time.**

2. Utah Energy Office Proposal

The Utah Energy Office ("UEO") has proposed what it calls an "Energy Efficiency Tariff" for interruptible transportation ("IT") customers of Mountain Fuel Supply. In order to qualify for service under this tariff, IT customers would have to submit a brief plan committing three cents per decatherm of expected usage toward direct natural gas efficiency improvements. The UEO provided only general guidelines of how the proposal would be implemented, and this lack of specificity raised concerns among the various industrial intervenors who stated that the record was insufficient to support the need for and merit of the proposal.

The UEO based its proposal on two major premises. First, the current relatively low cost for transported gas does not provide sufficient incentives for energy efficiency measures or proper market signals as to the risk of significantly higher future gas prices. Second, since the IT customers may retain the option of returning to the system as interruptible sales customers at average cost pricing, they are not fully exposed to the risk of a sharp gas price increase. Both of these factors will lead the IT customers to under-invest in energy efficiency/conservation to the potential future detriment of other customers and society in general.

The Commission recognizes the problem that existing market signals may not be sufficient to adequately provide long-term incentives for cost-effective investment in energy efficiency. They may also not promote global competitiveness of United States (or Utah) companies. This is a problem which must be addressed, both nationally and locally.

It is not clear, however, that the IT customers, with their relatively high load factors, will ever wish to return to interruptible sales customer status given the impact on average gas costs of the lower load factor GS-1 customers. The parties have agreed, and the Commission concurs, that this issue should be analyzed in a future proceeding.

The Commission has the statutory authority to encourage the conservation of resources and energy in determining just and reasonable rates under Utah Code Ann. § 54-3-1. Notwithstanding the sketchy nature of the Energy Office proposal, the Commission would perhaps have considered implementing it, or a similar proposal in this case were it not for the fact that we are adopting a cost-of-service stipulation in this case, signed by all parties including the Utah Energy Office. This proposal would alter the result of that stipulation which we have adopted. As we have indicated in Docket No. 90-2035-01, the least-cost planning proceeding for PacifiCorp, it is appropriate to address future capacity and energy needs during a period of relative excess supply in order to prepare for future demands for both utility services.

Similarly it is appropriate for the Commission to address future supply and demand issues, including efficient utilization of natural gas supplied or transmitted by Mountain Fuel Supply, during the current period of relative demand and supply balance in natural gas markets.

We commend the Utah Energy Office for bringing energy efficiency issues forward at this time. In the rate design portion of this order, we rejected GS-1 tariff concepts which would, perhaps, send a better signal to customers to invest in energy efficiency. This, not because the Commission rejects consideration of such concepts, but rather that a more comprehensive look at rates and energy efficiency is appropriate before the changes are made. We have elsewhere in this order determined that we will initiate an integrated resource planning effort for Mountain Fuel Supply. We hereby find that the Utah Energy Office proposal will not be adopted in this docket, but will request that the Utah Energy Office consider its proposal in the integrated resource plan context and participate in that process. The potential may exist for additional "windows of opportunity" for a program, such as the one proposed by the Utah Energy Office, in future cases. The Commission will require that it be analyzed within the broader implications of efficiency incentives for all ratepayers prior to implementation.

ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED that:

1. The Company file revised schedules and tariffs reflecting and incorporating the findings and conclusions of this Order and

calculated to result in annual revenues of $139,533,000 and yield an overall annual return of 11.03 percent beginning December 1, 1990.

2. The stipulation proposed by the parties on cost-of-service and the rate design issues in this case is approved and adopted as appended hereto.

3. The Company henceforth assume and carry the burden of justifying all interaffiliate transactions that bear on rates and services in all future proceedings.

4. The Company's actual capital structure is adopted, but we order that the Division shall conduct an examination of that capital structure to determine whether or not the costs of debt and preferred stock can be reduced.

5. The gas-planning function presently performed for the Company by Questar Pipeline shall be transferred to the Company.

6. The Company shall provide the Commission, Division and interested parties with a long-term, least-cost integrated resource plan within six months of this Order.

7. The Division shall establish a task force hereafter to consider various issues arising in this case which shall include but not be limited to the issues set forth on page 43.

8. To the extent that the Commission has inadvertently omitted from the ordering provisions of this Order any duty or obligation intended to be imposed upon the Company or Division, which duty or obligation is otherwise clear from the language of the the preceding portions of this Order, it is hereby incorporated herein by this reference and made a part hereof.

9. Any party, or any stockholder, bondholder, or other person pecuniarily interested in the Company may apply for rehearing of any matter determined herein. The application for rehearing must be filed within 30 days after the issue date of this Order. An application for rehearing not granted by the Commission within 20 days after filing is denied. If the application for rehearing is denied, a petition seeking judicial review of any matter determined in the Order must be filed within 30 days of the date the application is denied.

DATED in Salt Lake City, Utah this 21st day of November, 1990.

/s/ Brian T. Stewart, Chairman

/s/ James M. Byrne, Commissioner

(SEAL)

/s/ Stephen F. Mecham, Commissioner

Attest:

/s/ Stephen C. Hewlett, Commission Secretary

CONCURRENCE OF CHAIRMAN BRIAN T. STEWART AND DISSENT IN PART

I cannot concur with the decision of my fellow commissioners rejecting the 10 percent disallowance for affiliate transactions proposed by the Committee. In the last U.S. West rate case, docket number 88-049-07, the Commission expressed its concerns, quite clearly in my opinion, about affiliate transactions and the burden of proof relating thereto. We there ordered that the burden of proof to justify in toto the reasonableness of all affiliated transactions falls squarely upon the utility. We further stated that we would look at the reasonableness with which the utility responded to efforts by regulators to obtain information about affiliate transactions (referred to in this case as the attitude test). In my view, the Company failed both tests.

The first test was clearly not met by the Company inasmuch as it made practically no effort to substantiate the reasonableness of its affiliate transactions. Fortunately for the Company, the Division undertook a comprehensive look at such transactions, sufficient to satisfy my fellow commissioners. I believe that the utilities that we regulate must be on notice that inasmuch as they control the corporate structure which they choose to use, as well as the inter-affiliate transactions made, that the burden must fall totally upon them to justify each and every affiliate transaction--which transactions are encumbered by a presumption of suspicion and self-serving. Utilization of already stretched regulatory resources to seek-and-find-something-wrong is unacceptable to me. Regulators should only be required to review the affirmative case made by the utility.

It has been asserted that the Company passed the attitude test because it willingly made available whatever the Division requested. I believe that this assertion failed to take into account the Motion to Compel that the Division was forced to file in May of this year, and the effort of the Company to use the affiliate shield as justification for not making the appropriate gas supply models and necessary data available to the Division and the Committee. Though this was an isolated incident, in my mind it was a significant one.

I believe my fellow commissioners have been unduly patient with the Company on this issue, and I believe the Company should be grateful for their tolerance.

/s/ Brian T. Stewart, Chairman