Service Date: April 17, 1996

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER OF MONTANA-DAKOTA UTILITIES COMPANY, Application for Authority to Increase Rates for Natural Gas Service in Montana.	)	UTILITY DIVISION DOCKET NO. D95.7.90 ORDER NO. 5856b

FINAL ORDER

APPEARANCES

FOR THE APPLICANT:

John Alke, Hughes, Kellner, Sullivan, and Alke, Attorneys at Law, 406 Fuller Avenue, P.O. Box 1166, Helena, Montana 59624-1166, and Douglas W. Schulz, Senior Attorney, Montana-Dakota Utilities Co., 400 North Fourth Street, Bismarck, North Dakota, 58501

FOR THE INTERVENORS:

Robert A. Nelson, Montana Consumer Counsel, and Mary Wright, Staff Attorney, Montana Consumer Counsel, 34 West Sixth Avenue, P.O. Box 201703, Helena Montana 59620-1703, for the Montana Consumer Counsel

FOR THE COMMISSION:

Ron Woods, Rate Analyst, Mike Lee, Rate Design Bureau Chief, Mike Sheard, Rate Analyst, and Martin Jacobson, Staff Attorney, 1701 Prospect Avenue, P.O. Box 202601, Helena, Montana 59620-2601

BEFORE:

NANCY MCCAFFREE, Chair

DAVE FISHER, Vice-Chair
BOB ANDERSON, Commissioner
DANNY OBERG, Commissioner
BOB ROWE, Commissioner

INTRODUCTION

1. On July 3, 1995, Montana-Dakota Utilities Co. (MDU or Company), a division of MDU Resources Group, Inc., and a public utility providing both electric and natural gas (gas) services in eastern Montana and several neighboring states, filed before the Montana Public Service Commission (PSC or Commission) an application for approval of increased rates for gas service in its Montana service area.

2. In its application MDU proposed an increase of about 12 percent in residential rates and a decrease of about 8.4 percent in firm general and small interruptible rates. The proposed changes in rates amount to a total revenue increase of about $2.8 million per year. MDU also proposed several modifications to its tariffs, including to customer charges, rate structures, and certain pricing and operating procedures, inclusion of a weather normalization adjustment, and others.

3. In compliance with a settlement reached in MDU's next previous gas general rate case, Docket No. 94.4.17[1], which precluded further MDU rate changes to March 1, 1996 (with some exceptions), MDU's present filing was apparently timed to allow new rates, if approved by the PSC, to go into effect on or about

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[1] Docket No. 94.4.17 was consolidated with several other MDU gas-related dockets into Docket No. 94.9.39 for settlement purposes. The settlement was approved through PSC Order No. 5808 (October 26, 1994).

that date. Until that date interim rate relief was unavailable to MDU and, due to the proximity of this final order to that date, no interim rate relief for MDU has been considered by the PSC.

4. Also pending before the PSC is a final action on MDU's fall 1995 gas cost tracking adjustment procedure (tracker), Docket No. D95.10.145. MDU's request in that matter (revenue decrease of about $2.3 million) was approved by the PSC on an interim basis in Order No. 5870a (October 27, 1995). Intervenors have since indicated that no hearing is necessary on the matter and the PSC can move to a final order. That tracker proceeding has been consolidated with this present docket, for case management purposes, and the interim order will be approved as a final order, all provisions of it bearing solely on its interim nature to be disregarded.

5. On July 5, 1995, the PSC publicly noticed MDU's present rate application, inviting public comment and party intervention. The Montana Consumer Counsel (MCC or Consumer Counsel), Montana State University - Billings (MSU-B), the Montana Department of Environmental Quality (DEQ), and Interenergy Corporation (Interenergy) each intervened.[2]

6. During prehearing procedures the PSC reserved one issue pertaining to an MDU interconnect with Montana Power Company

[2] MCC generally participated in all aspects of the main case proceeding. MSU-B submitted prefiled testimony contributing to formulation of an additional issue, was involved in some exchange of discovery, but did not otherwise participate, appear at hearing, or enter its testimony into the evidentiary record. DEQ's status is explained at n. 3. Interenergy has not actively participated in the proceeding.

(MPC) at Billings, Montana. The parties directly involved in that issue, MDU and DEQ[3], have stipulated prefiled testimony into the record and have filed initial and response briefs on the matter. A PSC decision will be issued on the merits of the interconnection issue as soon as practical. Insofar as MDU or DEQ testimony or argument on the reserved issue may relate to any aspect of the main case (e.g., rates), it will also be considered as part of the record for purposes of this Order.

7. Hearing on MDU's application was held commencing January 10, 1996, in Helena. At hearing testimony and exhibits were received as evidence. Satellite hearings were held February 6 through 10, 1996, in several communities in MDU's Montana gas service area. The parties have now submitted their initial and response briefs on the main case.

[3] DEQ submitted prefiled testimony and participated in discovery in the main case, but, its interests are now focused on the reserved issue. DEQ did not appear at the main case hearing.

8. Review of the case indicates that further proceedings are necessary on an issue pertaining to rate base treatment of certain MDU ratepayer-funded reserves and MDU shareholder-funded reserves. Presently the PSC will accept MCC's position on the issue, but will develop an adequate supplemental proceeding (reserved issue) through which evidence on the amount involved and argument on the concept involved can be properly considered. If supported by facts and law the PSC intends disposition through an accounting order or similar mechanism, recovery, if any, to be included in MDU's next tracker filed subsequent to this Order.[4]

9. Except as may pertain to reserved issues or parts of issues reserved, the PSC has now considered the facts of record and the arguments submitted by the parties and finds, concludes, and orders as follows.

FINDINGS OF FACT, ANALYSES, AND DECISIONS

10. All introductory statements which can properly be considered findings of fact (or analyses or decisions) and which should be considered as such to preserve the integrity of this Order are incorporated herein as findings of fact.

REVENUE REQUIREMENTS

Capital Structure

11. In its application MDU proposed the following capital structure for its rate case presentation:

[4] This issue is discussed in more detail in the revenue requirements section of this Order.

	Amount (000)	Percent of Capitalization
Long-Term Debt	$149,303	53.39%
Preferred Stock	$ 5,050	1.81%
Common Stock	$ 30,934	44.81%
Total		100.00%

The capital structure proposed by MDU was not a contested issue in this docket. The Commission determines that the capital structure as presented by MDU is reasonable and that it will be used to calculate the composite cost of total capital in this proceeding.

Cost of Capital

Cost of Equity

12. Return on equity (ROE) is a contested issue between the parties. MDU has requested a 13.0 percent ROE based on the analysis and testimony of its witness Dr. J. Stephen Gaske. MCC has proposed a ROE of 10.75 percent based on the analysis and testimony of its witness Stephen G. Hill. Both witnesses relied on the Discounted Cash Flow (DCF) analysis in reaching their respective conclusions regarding the appropriate ROE. The major difference in the witnesses' proposals relates to the derivation of the growth rates used in the DCF formula and the treatment of flotation costs. The following shows the development of the ROE as proposed by the parties:

	MDU		MCC	
Dividend yield	6.16%[5]	6.16%[6]	5.65%[7]	6.35%[8]
Quarterly dividend yield adjustment	.17%	.21%	-0-	-0-
Expected growth	4.50%	5.50%	4.50%	4.64%
Investor required return	10.83%	11.87%	10.15%	10.99%
Flotation costs	.87%	.95%	-0-	-0-
Return requirement	11.70%	12.82%	10.15%	10.99%
Recommended range	11.70%	12.80%	10.50%	11.00%
Recommended ROE		13.00%		10.75%

[5] The information in this column reflects the witness's industry average information.

[6] The information in this column reflects the witness's industry average information.

[7] This is an MDU Resources specific calculation provided by Hill in his direct testimony at Schedule 6 of MCC Ex. 1. The dividend yield includes the quarterly dividend yield adjustment.

[8] The information in this column reflects the witness's industry average information. The dividend yield includes the quarterly dividend yield adjustment.

13. Gaske’s calculation of MDU’s required ROE includes a flotation cost adjustment. Gaske believes that the adjustment must be reflected so that investors will stay whole in the event of future public offerings of stock. He states that the adjustment is required to cover the issuance expense associated with past and prospective public offerings and to allow issuance of stock without dilution of book value. Gaske’s adjustment increases MDU’s average ROE by approximately 91 basis points, equating to an approximate $135,000 annual revenue requirement.

14. MCC opposes inclusion of a flotation cost adjustment to the ROE for several reasons. The most compelling is MCC’s assertion that MDU has incurred no costs because it has not issued stock in the past several years and has no plans to issue new shares in the near future. To MCC, since MDU has not issued stock in the recent past, nor does it contemplate an issue, MDU has no prospect of incurring the cost.

15. MCC asserts that the proposed flotation cost adjustment would allow MDU to recover “phantom” costs. To support its position MCC points to the fact that MDU has not issued additional common stock since at least 1990. MCC comments that, if flotation costs had been allowed between 1990 and 1994, MDU would have recovered costs that were not incurred. Absent the potential for issuance of common stock and therefore, no potential for expense incurrence, the MCC sees no rational basis for including the flotation cost.

16. Regarding Gaske’s argument that MDU shareholders should be protected from a dilution of the book value of their common equity when (and if) new common stock is issued, that is a matter of timing, not ratepayer responsibility. It is management’s

responsibility to determine the timing of the issuance of new shares. If management decides to issue new shares of common equity it is management's responsibility to issue those shares during favorable market conditions. If management fails to discharge this obligation and issues shares during an unfavorable market, it should not fall to the ratepayers to insulate the equity investor.

17. The arguments for the inclusion of a flotation costs adjustment are the same as the Commission has heard previously from MDU and from other utilities. Where utilities have argued that flotation costs are appropriate the Commission has consistently denied the related request. The Commission determines that it should continue this policy. When MDU issues new common stock it should include the associated costs in a subsequent general rate case.

18. Gaske and Hill both rely on a review of historical (earnings, dividends, book value, and market price) and projected (forecasts by analysts) growth rates. Each witness criticizes the other's development of growth rates.

19. Hill states that Gaske's growth rate range of 4.5 percent to 5.5 percent is not supported by the data purportedly relied on by Gaske. Hill indicates that Gaske's forward-looking Insitutional Brokers' Estimate System (IBES) growth rate data supports an average growth expectation of 4.2 percent, a number that is below the growth rate range found reasonable by Gaske. Hill further asserts that Gaske's historical growth rate information does not support the growth rate range Gaske found to be reasonable. Referring to MDU Ex. 11, Schedule JSG-2, p. 9, Hill states that the 10 year

historical growth for the sample companies averaged 4.8 percent, a number that is below the mid-point of Gaske's range, and that the 5 year historical growth was 2.8 percent. It would appear, based on Hill's critique of the data supporting Gaske's development of a reasonable growth rate range, that the range should be narrowed to 4.2 percent to 4.8 percent.

20. Gaske's criticism of Hill's development of a reasonable growth rate surrounds Hill's decision to cut the premium in market value over book value in half instead of using the current market-to-book ratio in his calculations. Hill, direct p. 30, provides the following as his reason for cutting the premium in half:

> Because a goal of regulation is to allow a utility to recover no more than its cost of capital, it is also reasonable to assume that investors would expect the market price/book value ratio to have a tendency toward unity. However, the price/book ratio is unlikely to reach 1.0 overnight and, on average, utilities will continue to issue stock at prices above book value. I believe that reasonable estimate of investors' expectations for utility price/book ratios is that it will range between current levels and 1.0. I have used the average as an estimate of investors' expectations for the future.

Gaske asserts that investors do not expect the market-to-book ratio decline as alleged by Hill. As support for this contention Gaske cites a June 30, 1995, issue of Value Line Investment Survey (Value Line) which provides estimates of the range of stock prices that Value Line is projecting for each of Hill's sample companies during the period 1998 to 2000, as well as the book value per share projected for that time period. Gaske, in rebuttal, JSG-4, p. 1, shows that the information in Value Line indicates that the mid-point of the range of projected stock prices, divided by the projected book value indicates a projected market to book value of 1.58 compared to the current market-to-book of 1.51. This data indicates that the market-to-book ratio will increase, not decrease, as asserted by Hill.

21. Gaske, rebuttal, JSG-4, p. 2, recalculates the growth rate of Hill's sample companies, backing out his assumption that market-to-book will decline. Backing out the assumption increases the growth rate for Hill's sample companies from 4.64 percent to 4.90 percent. If we add Gaske's recalculated growth rate of 4.90 percent to Hill's dividend yield of 6.35 percent, Hill's cost of equity for his sample companies would become 11.25 percent.

22. Based on the preceding discussion eliminating flotation costs and adjusting the growth rates of the witnesses the following ROE is developed:

	MDU		MCC	
Dividend yield	6.16%	6.16%	5.65%	6.35%
Quarterly dividend yield adjustment	.16%	.18%	-0-	-0-
Expected growth	<u>4.20%</u>	<u>4.80%</u>	<u>4.50%</u>	<u>4.90%</u>
Investor required return	10.52%	11.14%	10.15%	11.25%
Recommended ROE		13.00%		10.75%

23. The ROE witnesses also disagree in their conclusions regarding the risks associated with MDU's gas operations. Hill asserts that MDU's gas operations are less risky than the companies in his sample group, while Gaske argues that MDU is more risky than the companies in his sample group. As a result

of their risk conclusions the witnesses have increased and decreased their recommended returns above and below the returns for that of their respective sample companies.

24. Hill considers the financial risk of MDU and the cost of capital for MDU Resources in making his risk conclusions. Hill, direct, pp. 46-47, states the following in support of his risk conclusion and placement of MDU at the lower end of the equity range:

> MDU’s financial risk is similar to, but somewhat lower than, that of the gas distributors studied herein, as noted previously in my testimony. That, in addition to the fact that the cost of equity of MDU Resources -- MDU’s source of equity capital --appears to be considerably below that of a gas distributor, would indicate that a point estimate in the lower end of the range of equity cost estimates for gas distributors would be reasonable for ratemaking purposes. However, the financial risk differences between MDU and the sample gas distributors are relatively small and the equity cost estimates for MDU Resources are based on an analysis of the market data of only one company and are, statistically, less reliable than the equity cost estimates for the gas distributors. Therefore, an appropriate equity return for the Company falls at the mid-point of that market-determined range, or 10.75%.

This indicates that Hill’s criteria for using the lower equity return limit is quite meager, and dependent on his cost of equity capital for MDU Resources, which is less reliable than that for the sample group.

25. Gaske argues that MDU is riskier than the companies in his sample group. His arguments are contained in his direct testimony, pp. 29-39. In his conclusions on risk he provides the following reasons why MDU is riskier than his sample group:

> There are considerable risks associated with investments in gas distribution companies and these risks have increased in recent years. In my opinion, Montana-Dakota's overall risks are greater than those of any of the companies in the comparison group. The considerably higher business risk is due primarily to the small size of the Montana jurisdictional natural gas operations relative to the size of the comparison companies and the perceived risks of bypass due to the unusually large amount of direct competition with another gas utility. Montana Dakota's Montana operations also face regulatory risks that are above average relative to those of the comparison group. In addition, Montana-Dakota's financial risks are clearly greater than the average financial risks faced by the comparison companies.

26. The Commission is persuaded that Gaske's conclusions regarding increased risk, in comparison to the sample group, appear to be valid for financial risk and, to a limited extent, for business risk. MDU, in comparison to the sample group average, is financially more risky because it has a higher magnitude of debt in its capital structure and its bond rating is lower. In the area of business risk MDU's smaller revenue base, compared to that of the sample group, increases its risk, because MDU has a smaller proportion of return available to absorb fixed costs during periods of economic downturns. However, the argument that the threat of bypass is greater for MDU than for

the sample group is an argument that was not substantiated. All local distribution companies (LDC) are facing the threat of bypass as a result of increased competition in the energy market, whether it be direct competition with another gas utility or some other energy provider.

27. The Commission can exercise some discretion in determining a reasonable ROE. Through the exercise of that discretion the Commission considers consumer and utility interests, levels of risk, utility performance, and current trends as items that might affect the Commission’s determination of a reasonable ROE. The Commission’s acceptance of the argument that MDU has greater financial and business risk than the sample group of companies, entitles MDU to an increase in its ROE above that found reasonable for the sample group. In addition to being riskier than the sample group the Commission finds that MDU should be rewarded for its good management practices such as diversifying its gas portfolio, minimizing rate filings, and minimizing its costs of doing business. The Commission determines that MDU should be authorized a 12.0 percent ROE.

Preferred Stock

28. There is no contest in regard to any cost aspect of the preferred stock component of MDU’s cost of capital.

Cost of Debt

29. In its application for increased rates MDU proposed an average embedded cost of debt of 10.212 percent. In prefiled testimony MCC witness Hill challenged MDU’s calculation of debt costs and calculated that MDU’s embedded cost of debt should be

9.06 percent. At hearing Hill presented a revised exhibit indicating that MDU's debt cost should be 8.72 percent. The debt cost calculated by Hill is essentially the coupon cost of debt for MDU. MDU did not challenge the accuracy of Hill's revised debt costs, as calculated using Hill's assumptions.

30. However, Hill contended that the Commission should disallow recovery of approximately $15.1 million dollars of issuance related expenses incurred by MDU during 1991 and 1992, when the Company redeemed all of its outstanding debt. Hill states that the Company redeemed all of its outstanding debt because it wanted to change some of the terms and conditions contained in its First Mortgage Bond Indenture. Hill contends that the redemption of this debt in order to make changes to a bond indenture, produced no benefit for MDU's customers. He states that all benefit from the indenture changes flowed to the MDU shareholders.

31. MDU counters Hill's testimony through the rebuttal testimony of Douglas A. Mahowald. Mahowald states that MDU's customers did indeed benefit from MDU's 1991 and 1992 debt refinancing. He states that the primary purpose behind refinancing was to lower the company's overall cost of debt, not to gain any ability to restate the bond indenture. To support his position that the primary objective was achieved, Mahowald provided the cost of debt for the redeemed issues and the cost of debt for the new issues which replaced that debt.

32. It appears that MCC is asserting that all costs associated with the trust indenture revision and bond redemption program be disallowed. MCC reasons that the indenture revision and bond redemption program was a single transaction that

produced no proven ratepayer benefit, thus warranting disallowance. The Commission cannot accept the MCC's reasoning that this was a single transaction. Bond redemption and indenture revision are separate and distinct activities that can and do occur independent of each other with each having their own separate costs.

33. MDU states that it embarked on the refinancing program to lower the overall cost of its long term debt. As indicated above, in support of this statement MDU witness Mahowald provided an exhibit comparing the pre-refinancing and post-refinancing cost of debt. MDU's calculation of the effective cost of debt includes the cost of redeeming the existing debt and the unamortized issuance expense of approximate $15 million and shows that, prior to refinancing, MDU's effective cost of debt was 10.215 percent and, after refinancing, the effective cost was 9.508 percent. MDU further shows that this difference in the effective cost of debt reduced MDU's interest costs by $231,500 annually. This testimony indicates clearly that MDU's debt refinancing produced a net savings that benefit the ratepayer. While it may be true that MDU, in part, embarked on the refinancing program to gain the ability to revise the bond indenture, the act of refinancing the bonds reduced its overall cost of debt to the benefit of the ratepayer and, therefore, the Commission finds the costs recoverable.

34. The indenture restatement, as alleged by MCC, did produce benefits for the shareholders of MDU. The revision loosened the restrictions on purchase of encumbered property, it gave the Company greater flexibility to get involved in other forms of energy supply and increased the amount of bonds that

could be issued under the indenture. Since shareholders were the recipients of these benefits, the cost of the indenture revision should be their responsibility. It is estimated by MDU that included in the $15 million cost of refinancing is an estimated $50,000 cost incurred to have the original indenture restated. The number is an estimate. MDU was unable to determine, from the invoices received, the exact amount of the expense incurred and the amount stated could be more, or less, than that provided in the testimony. The Commission finds that MDU should reduce the costs included in its calculation of the effective cost of debt by $50,000, the estimated amount of the indenture revision costs.

Commission Decision on Cost of Capital

35. Based on the above findings and analyses, the Commission determines the following capital structure and composite cost of total capital to be reasonable:

	Amount (000)	Percent of Capitalization	Rate	Rate of Return
Long-Term Debt	$149,303	53.39%	10.212%[5]	5.452%
Preferred Stock	$ 5,050	1.81%	4.653%	0.084%
Common Stock	$ 30,934	44.81%	12.000%	5.377%
Total		100.00%		10.913%

Rate Base

[5] In the compliance filing the effective cost of long term debt will be reduced to reflect the Commission’s disallowance of $50,000 in bond indenture revision costs.

36. In its application MDU proposed an average original cost depreciated rate base of $19,955,349. In prefiled direct testimony MCC's expert witness proposed adjustments to decreasing MDU’s claimed rate base $2,491,568.

Unamortized Loss on Reacquired Debt

37. This issue (rate base treatment of unamortized loss), although contested at the time of hearing, is no longer contested. MCC, in its answer brief, p. 11, states A...it is now apparent that MDU did not double count the “amortized” or annual amount of the loss, and its proposal regarding the unamortized portion of the loss does indeed comply with the PSC’s methodology as approved by the Montana Supreme Court.”

1995 Plant Additions

38. MDU’s proposed rate base of $19,955,349 for its Montana gas operations is an average of its December 31, 1994, and December 31, 1995, balances. The 1995 rate base balances are pro forma balances constructed from company budget information. MDU asserts that the proposed 1995 post-test-year rate base adjustments are known with certainty and measurable with reasonable accuracy and, therefore, acceptable. MDU further asserts that the proposed rates will not become effective until April, 1996,[6] and therefore, to provide a better match between

[6] As indicated earlier, interim relief has not been available to MDU because of terms in a settlement.

cost levels being experienced during the rate effective period, the post-test-year adjustments should be accepted by the Commission.

39. MCC argues that MDU's post-test-year rate base additions, specifically plant in service, should be disallowed. MCC asserts that the 1995 pro forma balances for gas plant in service are speculative and the company is attempting to move the Commission to a future test year basis for establishing rate base with these types of adjustments. If accepted as proposed by the MCC, the Commission would reduce MDU's rate base by $1,050,987 ($2,768,059 plant additions - $1,717,082 accumulated depreciation). This reduction in rate base, using the Company's proposed rate of return, would reduce the revenue requirement by $197,507.

40. The Commission, on numerous occasions, has been asked to include post-test-year plant additions in the rate base of a utility[7]. The Commission has considered the requests, but has consistently rejected them, except when extraordinary circumstances were presented. However, the Commission's reasons for rejection have not been based on any policy in opposition to the concept, but, generally, on the failure of the utility to provide more than mere speculation on the valuation of plant additions, or to make proper matching adjustments to revenues and expenses associated with the plant additions, or to meet other criteria governing the allowance for post-test-year adjustments.

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[7] See, e.g., Matter of MPC, Docket No. 93.6.24, Order No. 5709d (April 28, 1994); Matter of MWC, Docket No. 92.4.19, Order No. 5625c (February 8, 1994); Matter of MWC, Docket No. 86.9.51, Order No. 5252b (June 30, 1987).

41. Because MDU has filed a request to include post-test-year plant in its revenue requirement calculation the Commission must consider the reasonableness of that proposal and whether the proposed adjustment is acceptable under the Commission's developed policy and administrative rules. MDU asserts that use of the proposed 1995 balances is acceptable under Commission policy and governing rule ARM 38.5.106[8], which states in part:

> ...no adjustments shall be permitted unless based on changes in facilities, operations, or costs which are known with certainty and measurable with reasonable accuracy at the time of the filing. No adjustment will be entertained unless it will become effective within 12 months of the last month of the test period as used in this section.

Based on the above MDU's proposal to include post-test-year plant additions has to meet three criteria before it can be considered an appropriate adjustment.

42. The first condition is that the adjustment must be based on a change in facilities, operations, or costs. Clearly an addition to plant is a change in facilities, therefore the first condition is met.

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[8] ARM 38.5.106 applies in regular filings. A similar rule, ARM 38.5.106, applies under optional filing standards.

43. The second condition that must be met is that the change must be known with certainty.[9] To meet the known with certainty condition MDU submitted an itemized list of all capital assets it would be funding during calendar year 1995. The listing submitted by MDU provides the Commission with ability to find that it is known with certainty that MDU will be funding capital assets in 1995, which is within 12 months of the close of the test year.

44. The last condition that must be met for an adjustment to be accepted is that it must be measurable with reasonable accuracy.[10] For post-test-year plant additions to be included in the revenue requirement the value of the plant must be reasonably accurate.

45. In its filing MDU stated that it would be making approximately $2.7 million in plant additions during 1995. The dollars of investment provided in the filing were budget amounts. To support its position that it had provided the Commission a reasonable measure of its 1995 capital expenditures MDU (Aberle, supplemental rebuttal) provided MDU's actual expenditures showing

[9] "known" means reasonably certain as to whether and when it will occur. See, e.g., Re Camden and Rockland, Maine and Wanakah Water Co.'s, 154 PUR 4th 89, 98, Maine PUC (1994).

[10] "measurable" means that the amount of the change is reasonably certain. See, e.g., Re Camden, n. 7.

that through September, 1995, MDU had spent approximately $2.1 million. If this nine months of actual cost is annualized, capital expenses for 1995 would approximate $2.77 million. This meets the measurable with reasonable accuracy condition.

46. The Commission includes in “measurable” the aspect of matching. For post-test-year adjustments appropriate matching adjustments to revenue and expense must be included. To support its proposal to include post-test-year plant additions in the rate base calculation MDU has made adjustments to revenue and expense associated with the additions. Matching is a point where MDU’s proposal differs from previous post-test-year adjustment presentations where companies have requested the inclusion of "ongoing" capital maintenance in rate base. The Commission's previous denials regarding post-test-year plant additions generally centered around the failure of the utility to make clearly appropriate adjustments to its revenues and expenses associated with the post-test-year additions. In this docket MDU has made matching adjustments to revenues and expenses for the post-test-year additions by adjusting such items as operating revenues for customer growth, salary and wage expense, depreciation expense, and cost of gas.

47. The Commission finds MDU has made a strong case for including post-test-year additions in its rate base. The Commission concurs with MDU that all reasonably necessary adjustments have been made for providing an appropriate matching of revenues, expenses, and rate base.[11] The Commission finds that

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[11] Because investment and recovery are ongoing events, but plant in service must be determined at a point in time, there can be no perfect match. See, generally, Matter of MPC, Docket No. 93.6.24, Order No. 5709d, para. 63 (April 28, 1994).

MDU’s request to include post-test-year plant additions in rate base should be accepted.

Unamortized Gas IRP Balances

48. MDU proposed to amortize costs associated with its gas integrated resource plan (IRP) over a 10 year period. With amortization MDU is entitled to reflect the unamortized balance in rate base. The proposal to include the unamortized balance in rate base is not in dispute, the dollar amount to be included in rate base is.

49. MDU proposed to increase its rate base by $357,318. This is the average 1995 balance of the unamortized portion of the IRP expense. MDU’s proposal to include the unamortized amount in rate base, as calculated, is a method of compensating MDU for the time value of the monies expended, which has been accepted by the Commission in other dockets. Under this proposal the unamortized balance included in rate base would decline as the costs are charged to expense.

50. MCC proposed that the Commission use a level rate base addition for IRP expense amortization. The level rate base addition proposed by MCC is the average balance of the unamortized IRP expense, and this addition would be included in rate base for the 10 year life of the amortization. MCC’s proposal would be a rate base addition of $187,686 for 10 years. MCC’s proposal reduces MDU’s claimed rate base by $169,832.

51. MDU stated that over the 10 year period of the IRP expense amortization both proposals yield the same return to MDU. MDU, however, resisted MCC’s proposal. MDU is concerned that as the unamortized balance in the account declines there will be a

point where the MCC's proposed 10 year average would be higher than the recorded book balance and a Commission sitting at that time might be tempted to allow only recovery of the book balance. If that occurred then MDU would be denied full recovery of its investment.

52. The Commission agrees, theoretically, with MDU's statement that both proposals will yield the same return to MDU. However, practical application will not produce that result. MDU's proposed declining balance rate base treatment will only yield the same return as the average proposal if MDU files rate cases with the Commission on a regular basis. MDU has not, historically, filed rate cases on a regular basis. That being the case the Commission accepts MCC's proposal to use the average balance, with the understanding that the average balance will remain in rate base throughout the entire 10 year period of the amortization.

Accumulated Provisions for Injuries and Damages

53. For this issue MCC witness Albert E. Clark proposed an adjustment reducing MDU's rate base by $404,542. He stated that the related reserves are funded through rates by inclusion of self insurance and pension and benefits in operation and maintenance expenses. Because the ratepayers are funding these reserves through rates they must be deducted from the rate base or the shareholders of MDU will be given the opportunity to earn a return on investment they have not made.

54. In rebuttal testimony MDU witness Rita A. Mulkern resisted Clark's proposed adjustment. Mulkern asserted that Clark's proposed adjustment is an example of picking and choosing

only those adjustments that reduce MDU’s revenue requirement. To support this statement Mulkern stated that Clark does not include as rate base additions an identical situation that exists on the asset side of the balance sheet, specifically referencing shareholder FAS 106 funding (where in 1993 and 1994 MDU paid into an external trust an amount not recovered from Montana customers that produced an asset) and a prepaid tax associated with pension and benefit liability. The company asserted that if the ratepayer funding of injuries and damages reserves are determined to be rate base deductions then the FAS 106 and prepaid tax must be added to the rate base.

55. The Commission finds that the MCC-identified reserve accounts are indeed customer contributed and the shareholders should not be allowed to earn a return on those monies. The MCC’s proposed adjustment reducing rate base by $404,542 is accepted. However, fairness dictates that it would be appropriate to examine MDU’s proposed rate base additions for the MDU-identified FAS 106 funding and prepaid tax. The Commission cannot now make a determination as to the reasonableness of MDU’s proposed adjustment, therefore, it will reserve that aspect of this issue. The commission will formulate a proper proceeding to obtain evidence and argument on the concept and the amount involved. Initially, MDU should calculate the FAS 106 funding and prepaid tax (associated with the pension and benefit liability) and provide that information to the Commission and MCC, along with a narrative explaining why those balances should be included in rate base. Necessary proceedings will follow. If MDU prevails on the issue, rather than another immediate rate change, the Commission intends to allow for an accounting order

or similar mechanism and a rate change to take place concurrent with a subsequent MDU tracker adjustment.

Construction Work In Progress

56. In its rate base calculation MDU has included $165,545 in construction work in progress (CWIP). The CWIP included is that portion (of CWIP) for which MDU is not accruing an allowance for funds used during construction (AFUDC). MDU reasons that maintenance of service requires an ongoing investment in CWIP and that it should be compensated for that investment which does not accrue the AFUDC. To receive this compensation MDU asserts that it should be allowed to earn a rate return on the average balance in CWIP by including it in rate base.

57. MCC argues that MDU should not be allowed to include CWIP in its rate base calculation. MCC states that, by definition, the investment in CWIP provides no benefit to the ratepayer because the assets are not used and useful in the provision of service and therefore, not includable in rate base under the used and useful statute.

58. The MCC's argument for excluding the CWIP balances from rate base is valid and consistent with the statute. In regard to Commission valuation of property, sec. 69-3-109, MCA, includes only the "value of the property of every public utility actually used and useful for the convenience of the public." CWIP is not used and useful and, therefore, is not includable in rate base.

Thirteen Month Average Balances

59. In its filing MDU developed its average test year rate base by computing the components of plant in service and accumulated depreciation using beginning and ending balances for

those accounts. MCC witness Clark proposes use of a thirteen month average balance for purposes of calculating plant in service and accumulated depreciation. This proposal decreases MDU's net plant in service by $426,843 and reduces the revenue requirement by $80,215. Clark asserts that use of the 13 month end balances, for plant in service and accumulated depreciation, provides a better match of test year revenues and expenses to the components of the rate base.

60. MDU states that the Commission's minimum filing standards in the administrative rules contemplate use of the beginning and ending balances for the accounts. MDU also states that Commission precedent in regard to MDU's calculation of these rate base components has been use of the beginning and ending balances.

61 Both methods of calculating the average to be included in rate base have been accepted by the Commission, therefore, which calculation to use is Commission discretion. The Commission finds, based on precedent applying to MDU, that it should continue use of the beginning and ending balance.

62 The following proposed rate base adjustments of the MCC (not rate base adjustments associated with post-test-plant additions) were not rebutted by MDU:

Material and Supplies	$2,252
Prepayments	501,744
Customer Advances	215
Gas Stored Underground	244,182
Accumulated Deferred Income Taxes	(68,039)
Total Adjustment	$680,354

Since MDU did not rebut these proposed adjustments to its rate base the Commission finds the adjustments reasonable and concludes that they should be accepted.

63 The Commission’s acceptance of MDU’s proposal to include post-test-year plant additions dictates that the Commission reject all rate base adjustments proposed by MCC that were reversals of MDU’s adjustments in calculating an average 1994-95 rate base.

64 Later in this Order the Commission will find that MDU’s proposed depreciation rates should be rejected. This rejection will require the Commission to reflect an adjustment decreasing MDU’s reserve for depreciation. The Commission finds that MDU’s reserve for depreciation should be reduced by $63,397.

65 Based on the preceding the Commission finds MDU’s original cost depreciated rate base to be $19,959,181. Unless otherwise specifically provided in this Order, all adjustments to rate base, revenues, and expenses proposed by the MCC reversing the effects of MDU’s proposal to include post-test-year plant additions are denied.

Expenses

66 MDU proposed total test period operation and maintenance (O&M) expenses of $42,409,737, which includes pro forma adjustments decreasing expenses by $1,689,165. Only those items of expense that remain a contested issue will be addressed in this section.

Pension and Benefits

67 MDU proposed an increase in its fringe benefit costs of $308,748. As stated by MDU the increase is due primarily to its implementation of SFAS 106, Accounting for Post Retirement Benefits Other Than Pensions ($262,401). Other fringe benefits increased or decreased slightly for a net increase of $46,347.

68 MCC objects to MDU’s proposal to adjust fringe benefit costs for workers’ compensation, group hospitalization and life insurance, pension costs, deferred compensation, and the tax free option plan. MCC argues that based on the testimony filed in this docket, and the responses to data requests, the Company’s proposed changes to these costs have not been supported.

69 In its rebuttal to MCC witness Clark’s proposed adjustment, MDU did not challenge the assertion that the proposed changes are not supported by substantial documentation. MDU attacks the adjustment as invalid because Clark begins his adjustment using 1994 actual expenses and allocates those expenses to the Montana operations based on the 1995 allocation factors. MDU asserts that it is inappropriate to allocate 1994 expenses using 1995 allocation factors because it denies the 1995 expense level recognition while accepting the 1995 allocation.

70 The Commission disagrees with MDU’s assertion that Clark’s adjustment is invalid because of the mixing of the 1994 expense and 1995 allocation. MDU’s jurisdictional cost allocations generally become known in February of each year and are effective until the succeeding February. The fact that the 1995 cost allocation became known and was used by the witness to allocate an actual 1994 expense does not render the adjustment invalid. The purpose of cost allocation is to assign the cost to the service provided. The use of the most recent allocation to

determine the pro forma expense simply recognizes the stated purpose of cost allocation. Clark says no increase in the overall cost level of expenses will be experienced, but there is a change in the cost allocation that will affect where and how those costs are assigned. There is no inconsistency.

71 MDU failed to provide any substantial documentation in support of its proposed adjustments to fringe benefits and, therefore, the Commission finds that the adjustments should be rejected. The MCC's proposed adjustment decreasing expenses by $55,412 should be accepted.

Labor

72 MCC proposed total adjustments decreasing MDU's test period labor expenses by $220,701. This adjustment includes a reduction in overtime and temporary wage costs and reversal of MDU's proposal to reflect a union and non-union pay increase. The reversal of the union and non-union pay increase for MDU employees was not disputed by MDU because it did not occur. MDU did, however, dispute the MCC's proposal to reverse the wage increase for MDU Resources employees because those pay increases did occur. At hearing MCC witness Clark accepted MDU's assertion that the MDU Resources, Inc., wage increase did occur and that his proposed labor decrease should be reduced by $16,764.

73 There is only one contested issue remaining between MDU and MCC over the calculation of labor expense. Clark contended that MDU's test year expense for overtime and temporary labor costs are abnormally high. Since it is his belief that this test year expense is abnormally high, he proposed to determine overtime and temporary help costs on the basis of a five year

average (1990-94) of the dollar costs incurred by MDU for these expenses.

74 MDU did not oppose the MCC's conceptual proposal regarding averaging to determine an appropriate expense level for overtime and temporary help. It did however, oppose the use of dollars as a basis for that averaging. MDU asserted that Clark's use of dollars to determine the appropriate level for this test period expense is improper because the dollar averaging proposal reflects an averaging of outdated wage rates to determine the test period expense. MDU proposes to use the five year average of hours of overtime and temporary help multiplied by the current wage levels to determine this expense. MDU's proposed average hour method would decrease Clark's labor adjustment by an additional $43,804.

75 The Commission accepts Clark's position on use of a five year average. However, MDU's proposal to use average hours times current wage rates is more reasonable than Clark's proposal to use dollars. Clark's proposal to use average dollars incurred does incorporate outdated wage rates, thus it does not provide as accurate a portrayal of the test year expense as MDU's proposal. The Commission finds that average hours of overtime and temporary help should be used to calculate this labor expense. MCC's proposed labor adjustment of should be reduced to $160,223.

Insurance

76 Using the latest available premium information MCC recalculated MDU's insurance expense. Except for two categories of insurance, MCC allocated each of the costs to the gas utility using the same allocation factor as MDU. MCC challenged the

validity of MDU's allocation factor for the insurance categories of Self Insurance-General Liability, and Excess Liability-Public Liability and Property Damage. As adjusted by the MCC, pro forma test year insurance expense would be reduced by $87,373.

77 Clark testified (direct, p. 11) as follows regarding his concerns about MDU's allocation of the liability insurance to the gas utility:

> ...I have allocated each of the liability insurances to the gas utility on a factor which is an unweighted average of plant and employees. The gas utility portion is then allocated to Montana operation using a factor of O&M expenses less cost of gas and administrative and general expenses. This is the same factor that MDU used for this purpose.
>
> In my view, MDU has allocated an excessive portion of the costs of the liability coverages to the gas utility. In all cases MDU used an allocation factor of 63.9%. The explanation of the allocation factor, however, differs among the coverages in question. For the Self Insurance-General Liability MDU states that the allocation is based on "the five year average of incurred losses and year-end customers." For the first layer of Public Liability and Property Damage-Excess Liability (AEGIS), MDU simply states that "separate invoices are issued by the broker to each company for its share of the premium." There is no explanation of whether the gas distribution operation is a "company" in this reference or how the costs are then allocated/assigned to the gas utility. The second layer of Public Liability and Property Damage-Excess Coverage is allocated exactly like the first layer. The explanation clearly indicates that "newly

> acquired companies" are not bearing any of the cost of these coverages.
>
> I have allocated the costs of all of these coverages on the basis of an unweighted average of the corporate overhead allocation factors for plant and employees. The resulting average of 32.9% and 44.6% is 38.75%. This adjustment reduces the test year pro forma expenses by $87,373.

78 In its rebuttal MDU (Mulkern, pp. 5-6) resisted Clark's proposed adjustment modifying the allocation factors for its liability insurance coverages. MDU made the following statements regarding its proposed allocations:

> The self insurance program for general liability applicable to Montana-Dakota is allocated between gas, electric, propane and merchandise operations on the basis of exposure (customers) and risk (losses). Therefore, the allocation of 63.9% to the gas utility reflects actual experience, which is a proper allocation. Mr. Clark's proposal to allocate Montana-Dakota expense based on plant and employees rather than actual experience, because he doesn't like the answer, is unfounded and plain wrong.
>
> The invoice issued to Montana-Dakota by the broker for its first layer of Public Liability and Property Damage-Excess Coverage (AEGIS) is for gas, electric, propane and merchandise operations. It is allocated to each of these segments on the same basis as self insurance, that is on exposure (customers) and risk (losses).
>
> The premium for the second layer of Public Liability and Property Damage-Excess Coverage is applicable to MDU Resources Group, Inc., and is allocated between

> Montana-Dakota, Williston Basin Interstate Pipeline, Fidelity Oil Group, Inc., and Knife River Coal Mining Company base on each company's ratio of the first layer. Montana-Dakota's portion is then allocated to the gas utility on the basis of customers and losses, the same as the first layer. MDU Resources had originally purchased its excess layer of Pubic Liability and Property Damage coverage for the catastrophic exposures of its principal businesses. When the coverage for the excess layer was extended to the newly acquired companies, there was no additional charge required by the underwriter. Therefore, the newly acquired companies are excluded from the allocation, since they have caused no additional expense. Mr. Clark's adjustment is flawed and should be rejected, which would increase his recommendation by $74,416.

79 The issue before the Commission on this matter is which allocation factor(s) are appropriate for this insurance coverage. The testimony on the matter supports MDU's allocation. MDU's allocation is predicated on exposure (customers) and risk (losses) for a particular business segment. MDU's allocation factors of exposure and risk are quantifiable (customer count and historical losses) and directly related to the expense being allocated and, therefore, reasonable. The Commission finds that MCC's proposed insurance expense adjustment should be rejected insofar as it relates to modification of the allocation factors. The Commission further finds, as proposed by the MCC, that MDU's insurance expense should be reduced by $12,957 to reflect the latest known premiums ($87,373 - $74,416 ‘ $12,957).

Postage

80 MDU proposed to increase postage expense by $28,043 to reflect a postage increase effective January 1, 1995, and expected postage levels. MCC proposed that MDU be allowed an increase of $15,905.

81 MCC proposed reducing MDU's claimed increase in postage expense by $12,129, claiming that the adjustment as proposed was not supported. As justification for this reduction MCC cites the supporting documentation supplied by MDU. MDU's supporting documentation was a single workpaper that listed the actual cost, the pro forma cost, and the difference. In an attempt to elicit additional documentation for the proposed adjustment MCC submitted a data request to MDU on the subject and the MDU response indicated that there was no additional documentation for the claimed increase. Since MDU's proposed postage increase of approximately 17 percent, an amount in excess of the approximate 10 percent postal rate increase, was not supported by corroborating evidence, the MCC proposed that MDU be allowed only a 10 percent increase for recovery of the postal rate increase.

82 In Mulkern's rebuttal testimony (p. 8), she stated that Clark's proposed adjustment reducing the pro forma expense should be rejected by the Commission. In support of that position she developed a 1995 annualized postage expense. She stated that actual postage expense through August 31, 1995, was $140,458. If this eight months of actual expense is annualized postage expense for 1995 would approximate $210,700. She further stated that this annualized expense is approximately $6,000 more than that requested by MDU in the filing.

83 In its initial brief the MCC makes the following statement regarding MDU's proposed postage expense adjustment: "It is not appropriate, however, to use partial results, annualized, for a single post test year item for which the original estimate was never supported in the first place." The Commission agrees with MCC. MDU should have had support for this adjustment at the time it included the adjustment in its original filing. Clearly, based on the workpaper and the response to the data request, MDU's proposed adjustment was devoid of supporting documentation. The Commission finds that MCC's proposed adjustment decreasing postage expense by $12,129 should be accepted.

Dues

84 In his prefiled direct testimony MCC witness Clark proposed an adjustment removing the Montana gas operation's portion of dues paid to the Western Environmental Trade Association (WETA) and recomputed the allowable portion of dues for the American Gas Association (AGA) and the local chambers of commerce (COC's). Clark stated that these proposed adjustments are being made because they are consistent with the treatment afforded these costs in prior Commission decisions.

85 Clark removed $235 in dues paid to WETA based on the Commission's decision in Docket No. 90.6.39, Order No. 5484m. MDU did not contest this proposed adjustment and the Commission, based on its prior decision, determines that the adjustment acceptable.

86 Clark eliminated $721 and $2,568 in dues paid to the AGA and the COC's, respectively. Clark stated that the AGA

adjustment was consistent with the Commission's decision in MPC Docket No. 93.6.24, wherein the Commission disallowed 9.05 percent of the AGA dues because they were costs for lobbying and promotional advertising. Clark relied on the Commission's decision in MPC Docket No. 88.6.15, Order No. 5360d, to support his proposed 40 percent reduction in dues payments to the COC's.

87 MDU objected to both the AGA and COC's adjustments. MDU states that Clark's 9.05 percent AGA disallowance percentage is inappropriate because his source information, a NARUC audit of 1991 AGA expenses, is outdated. MDU argued that the appropriate source data is a NARUC audit of 1994 AGA expenses that shows a percentage of 5.65 percent. The 5.65 percent developed by MDU from the 1994 expenses includes 5.22 percent for advertising and .43 percent for lobbying. The .43 percent for lobbying includes only those dollars for the Congressional Relations Division that are defined by federal law as lobbying.

88 At hearing, during cross-examination, Clark agreed that the Commission should use the most recent audit information, but did not agree that the 5.65 percent was the correct number. He indicated that he was unsure as to whether the 5.65 and 9.05 percentages were derived in precisely the same manner. He indicated that he believes that a portion of the dollars from the Marketing Division and Government Relations Division should be included in the calculation of the percentage.

89 The Commission agrees with Clark that the percentages do not appear to be analogous. Examination of MDU's testimony (Mulkern, rebuttal, pp. 7-8) would indicate that only the direct costs for lobbying have been included in MDU's calculation of the percentage. Certainly there are indirect costs attributable to

the function that have not been included. The Commission, absent clear showing that the numbers are analogous and having already accepted the 9.05 percent as reasonable in another docket, finds that the MCC's adjustment reducing costs by $721 should be accepted.

90 MDU argued that Clark's adjustment to COC's dues should be rejected because these enterprises are designed to promote economic development, stimulate trade, and increase population in the service area to the benefit of existing customers. The Commission realizes that COC's may generate potential benefits for ratepayers, but parts of those dues are used for lobbying activities, the recovery of which would be improper through rates. The Commission, since Docket No. 88.6.15, has consistently disallowed 40 percent of the dues paid local COC's and sees no reason for changing that policy. MCC's proposed adjustment reducing expenses by $2,568 should be accepted.

Advertising

91 MDU included $50,146 in promotional advertising expenses in its cost of service, contending that these costs meet the statutory and Commission criteria for inclusion and recovery. MDU asserts that its advertising campaigns for Residential Space Heating ($10,314), Nontraditional Residential Space Heating ($4,051), Decorative Appliances ($17,079), Residential Water Heating ($1,281), and Alternative Fuel Vehicles ($17,421) are recoverable costs. MDU argues that these campaigns either promote conservation or improve load factor and are, therefore, recoverable costs.

92 MCC has proposed that the Commission disallow recovery of the entire $50,146 in promotional advertising expenses claimed as recoverable by MDU. Clark states that the Residential Space Heating, Nontraditional Residential Space Heating, and the Residential Water Heating campaigns all serve to promote the use of gas at peak times and only serve to exacerbate any supply or delivery constraints that could develop in the winter season. The Commission concurs in Clark’s observations and finds that MDU’s request to recover these claimed advertising expenses because they promote conservation should be denied.

93 With regard to MDU’s Decorative Appliance advertising campaign MDU stated the purpose of this campaign was to improve the company’s load factor and provide an alternative fuel to its customers. Clark observed that the sale of additional gas is most likely the real goal of this campaign and the costs are therefore, not appropriately included in rates. He further observed that most of the decorative appliances would consume more gas in the winter than in the summer, thus the claimed load factor improvement is probably a myth. Again, the Commission agrees. These appliances are more likely to increase peak demand rather than improve load factor. The Commission finds that MDU’s request to recover these advertising costs should be denied.

94 MDU claimed that the last advertising campaign, for Alternative Fuel Vehicles, promotes conservation and enhances the environment and therefore, the cost should be recovered. MCC agrees with MDU’s claims that this campaign promotes conservation (although that conservation is in gasoline) and is cleaner burning. MCC, however, disagrees that these costs are recoverable. MCC maintains that the campaign actively promotes

the use of natural gas, not its conservation, and, therefore, the costs should not be recovered. The Commission disagrees with the MCC position on recovery of these costs. The Commission determines that substituting the more environmentally friendly compressed natural gas for gasoline, thus conserving the gasoline and preserving the environment, does qualify this expense as recoverable under the Commission’s criteria. The Commission finds that MDU should be entitled to recover the $17,421 in advertising expense associate with the Alternative Fuel Vehicles campaign.

Cost of Gas

95 MDU claimed a pro forma cost of gas of $32,825,621, representing a reduction of $2,184,531 from the per books cost of gas. For reasons explained later in this Order the Commission has rejected MDU’s proposed 1995 adjusted sales data. Therefore, it is incumbent on the Commission to specify the appropriate sales volumes for calculation of the cost of gas. The Commission finds that MDU should use its 1994 annualized volumes, normalized for weather and adjusted for 1995 customer growth. The calculation should also use the unrebutted loss factor of -0.84 percent, determined appropriate by the MCC and accepted by the Commission.

96 Calculating the cost of gas in the manner described above the Commission finds that MDU’s pro forma cost of gas should be $33,651,397, a reduction from the per books number of $1,358,755. The reduction in the cost of gas calculated by the Commission is less than the amount calculated by MDU. The

Commission’s cost of gas determination results in an increase in MDU’s O&M expenses of $825,776.

Inflation Adjustment

97 In this filing MDU proposed an attrition adjustment of 2.8 percent applied to all O&M expenses not otherwise adjusted by the company. This adjustment increases the pro forma operating expenses of MDU by $50,404. The inflation factor used by MDU was calculated using the average increase in the consumer price index for 1993-94.

98 MCC opposes MDU’s proposed attrition adjustment for three reasons. First, MDU did not file this case under the Commission’s optional filing standards, which specifically provide for this adjustment. Second, the adjustment is not a known and measurable change, as the Commission has applied the term under its traditional rules. Third, the adjustment does not conform with the Commission’s approved methodology in Docket No. 93.6.24, Order No. 5709d, paras. 113-120.

99 MCC is correct that the Commission’s traditional filing rules do not specifically allow for the filing of an attrition adjustment. Although the adjustment is not specifically allowed for by rule, there is no prohibition in the rules forbidding a utility from requesting such adjustment. Since there is no prohibition, the utility has the right to request the adjustment and the Commission cannot use the silence of it rules as a reason for rejecting it.

100 However, MCC’s two remaining reasons for rejecting the adjustment are valid. Under the traditional rules, for an adjustment to be considered by the Commission it must be known

and measurable with reasonable accuracy. Application of a percentage increase, developed by an index, to an aggregate of expenses, which may or may not have a correlative relationship to the index, cannot be characterized as known and measurable.

101 MCC's second reason for objecting to the attrition adjustment is MDU's failure to calculate the adjustment in a manner consistent with Commission precedent. MCC cites Commission Order No. 5709d as precedent for the calculation of an attrition adjustment. Paraphrasing the order, the Commission there determined that it was inappropriate to use two yearly averages (such as MDU did in this Docket) to calculate the adjustment and that the appropriate measure is the index change during the test year.

102 Based on the preceding, the Commission finds that MDU's request to apply an attrition adjustment to the expenses not otherwise adjusted should be rejected.

103 In his prefiled testimony Clark proposed a reduction in expenses associated with the Schuchart Building in the amount of $13,887. Clark's proposed adjustment is calculated by imputing the average cost per square foot currently being experienced by the other tenants in the building, representing a rejection of MDU's proposal to assign all residual costs of the building to MDU. MDU did not rebut this adjustment. The adjustment appears to be reasonable an is, therefore, accepted by the Commission.

104 Clark proposed two other unrebutted adjustments to MDU's O&M expenses. Clark proposed reducing expenses by $415 to exclude employees costs of attending out-of-area board of director meetings and he proposed removal of $6,782 of labor expense increase from MDU's office closing adjustment. The net

effect of these two adjustments is to increase O&M expenses by $6,367. The Commission finds both of these adjustments were supported by the record and should be accepted.

105 The Commission finds that pro forma operation and maintenance expenses total $42,894,262 recognizing total pro forma adjustments decreasing per books expenses $1,204,640.

Depreciation

Depreciation Expense

106 MDU proposed total pro forma depreciation expenses of $2,024,703. In 1992 MDU engaged the services of Stone and Webster for purposes of preparing a depreciation study for the gas utility. This study resulted in adjusted depreciation rates for MDU’s gas utility operation. The adjusted depreciation rates, using December 31, 1994, plant balances, increased MDU’s total depreciation expense by $138,660.

107 MCC witness Robert G. Towers has proposed that MDU’s Depreciation Expense be reduced by $229,585. Tower argued that the depreciation rates for the plant accounts “mains” and “services” should be reduced from that proposed in the study. The adjustment in these depreciation rates accounts for the entire depreciation expense reduction of $229,585 proposed by Tower. It is Towers’ contention that the negative salvage allowances of 40 percent and 140 percent proposed in the depreciation study for mains and services, respectively, are not justified by Company experience and are supported by insufficient data. He proposed that the negative salvage allowances for these accounts remain at there current level of 30 percent for mains and 100 percent for services.

108 William K. Strand, MDU's depreciation witness, in his rebuttal testimony, maintains that MDU's negative salvage allowances are amply supported by Company records. He maintained that the study relied on Company records of salvage experience related to the level of retirements, from 1968 to 1991, in determining the proposed salvage allowances. Further he asserted that these records, on a whole-history basis, support a negative salvage of 28.1 percent and 128 percent for mains and services, respectively, and the 1991 ten year average supporting a 40.6 percent and 167.5 percent negative salvage for the accounts.

109 While it is true that the historical Company records support the negative salvage allowances proposed by Strand in his depreciation study for the accounts of mains and services, the Commission believes the information should be discounted.

110 The testimony in this docket indicates that since the 1960s the material of choice for distribution mains and services has been plastic. Further, the information reveals that 90 percent of the pipe installed in MDU's distribution system is of plastic materials. The historical information relied upon by Strand to develop the negative salvage values for the accounts of mains and services would primarily relate to the removal of steel piping not plastic. This is so because the historical salvage and removal costs incurred by MDU would mainly relate to steel pipe that has reached the end of its service life.

111 MCC asserted that since MDU's current investment base is primarily plastic pipe it would be inappropriate to apply a salvage and removal cost estimate based on experience with steel pipe. To support that assertion MCC cites MDU's response to MCC-113, Docket No. 94.4.17, from MDU's witness Strand. In that data

request the MCC asked the witness to provide recommended salvage estimates contained in other recent depreciation studies prepared by him. In the response the witness indicated that for plastic distribution mains he had recommended negative salvage of -20 and -15. In the one instance that he provided a negative salvage for plastic distribution services he recommended a -60. The negative salvage values for plastic mains and services is significantly lower than that recommend for MDU (-40 mains and -140 services), which is now primarily plastic.

112 Based on the preceding the Commission adopts MCC’s proposed negative salvage values for purposes of calculating depreciation rates for the mains and services accounts. Using the plant-in-service values approved in this docket and applying MCC’s depreciation rates to those values, the Commission finds MDU’s depreciation expense to be $1,781,674.

Operating Revenue

113 MDU proposed total test period operating revenues of $47,270,015. MCC proposed adjustments increasing the operating revenues of MDU by $585,978.

Sales and Transportation Revenue for Customers at 12/31/95

114 MCC’s witness Clark contended that MDU’s proposed adjustment decreasing operating revenues by $985,778 to reflect decreased average usage per customer is inappropriate. He stated that MDU, using a linear regression analysis of the historical usage, estimated the change in average use per customer and determined that use per customer was declining. He argued that MDU’s use of the linear regression analysis to determine average

usage and reduced revenues is not a known and measurable change. Clark asserted that the proposed adjustment is hypothetical in nature and not supported by credible evidence.

115 MDU, through its witness R. J. White, countered that the adjustment is appropriate. White contended that the proposed adjustment to reflect decreased consumption per customer has been occurring and will continue to occur and that his statement is supported by his linear regression analysis. He stated in his rebuttal testimony that Clark does not dispute that use per customer is declining, nor that appliance efficiencies are increasing, and thus use per customer will continue to decline. He stated that the Company’s adjustment had used actual Montana billing data, normalized for weather, and that the regression analysis is a standard statistical tool and, therefore, the Company’s proposed revenue adjustment does represent an known and measurable change.

116 It may be true that use per customer is declining and appliance efficiencies are increasing. This observation however, and use of linear regression analysis to determine average usage per customer and reduced revenues does not represent a known and measurable change. As stated by MDU’s witness, the linear regression analysis is a statistical tool. Statistics is the discipline that deals with the study of a universe of information through the medium of samples to develop an interrelationship. The statistical tool, linear regression analysis, is used to develop a statistical inference. While one may be reasonably confident that the statistical inference developed through the analysis is accurate, within certain confidence levels, it is still a prediction not representing a known and measurable

change. The Commission finds that MDU's proposal to decrease operating revenues by $985,778 should be denied.

Annualization of Customers

117 MCC asserted that MDU's proposal to provide revenues from the sale of gas on an annualized basis as of December 31, 1994 is inappropriate. Clark indicated that the basis of any such adjustment should attempt to match the revenues included in the test year with the investment in rate base. He stated that MDU has proposed annualization of customers as of December 31, 1994, while using an average rate base, thus producing a mismatch between revenue (year end) and rate base (average). MCC's proposed adjustment would reduce MDU's revenues by $350,088.

118 MDU, through its witness Mulkern, countered that this adjustment is appropriate and necessary if the Commission accepts MDU's proposal to use an average 1994-95 rate base as proposed by MDU in its filing. This is true. The Commission's acceptance of MDU's proposal to use the average 1995 rate base requires MDU to annualize 1994 revenues in order to achieve proper matching of the rate base and revenue at average levels for 1995.

119 The Commission finds the MCC proposal to reduce MDU's revenues by $350,088 should be denied. The denial of this adjustment has no effect on the test period revenues of the utility, because the adjustment is already incorporated.

Penalty Revenues

120 MDU excluded all penalty revenues from its pro forma operating statement. MDU states that exclusion of these revenues is appropriate because these revenues are received from customers

who do not like to pay penalties and are likely to take measures to insure the penalty situation does not recur. That being the case, MDU asserts that penalty revenues should not be assumed to be reoccurring.

121 MCC argued that penalty revenues should be included in the pro forma operating statement. MCC witness Clark stated in his testimony that he has reviewed MDU's actual experience with penalty revenues since the inception of the tariff provision. This review revealed that during the period 1990 through 1994 the company on average collected $20,387, annually, in penalty revenues. Clark, based on this review of historical penalty revenue collection, proposed an increase in MDU operating revenue of $20,387.

122 Based on the historical review it would improper to assume that MDU is going to collect no revenues from the penalty provisions of its tariff. The Commission determines that MCC's suggested operating revenue increase is reasonable and that MDU's revenue should be increased by $20,387.

Sales and Transportation Revenue

123 MCC witness Clark proposed what he considered known and measurable changes to MDU's sales and transportation revenues. Clark stated that MDU's revenues should be adjusted to recognize the complete loss of Cenex and Conoco as transportation customers and Elk River Concrete's switch from Rate 70 to Rate 81. The revenue changes proposed by the MCC reduce MDU's operating revenues by $121,246.

124 MCC resisted MDU's proposal to further reduce revenues to reflect the loss of Western Sugar's transportation revenues

and the proposal to switch Rocky Mountain College, MSU-B, MetroPark, and Holiday Inn from Rate 70 to Rate 81. MCC argued that Western Sugar is continuing to transport gas on the system at a level that approximates historical levels, therefore, it would be inappropriate to remove the revenue. With regard to the proposal to switch customers from Rate 70 to Rate 81, MCC stated that it appears that none of these customers have yet made the necessary changes to their own facilities that would enable them to switch rates.

125 The Commission concurs with MCC’s analysis of the known and measurable changes that should be allowed. The Commission determines that MDU’s operating revenues should be reduced by $121,246.

Customer Growth

126 Customer growth not recognized in the test period operating revenues will generate additional annual revenues for the utility. Based on information provided by MDU, reversing their declining use per customer calculation, customer growth in the residential and firm general service classes will generate additional revenues of $247,094.

Commission Determination

127 The Commission determines, based on the preceding, that MDU’s test period operating revenues should be $48,402,028.

Taxes Other Than Income

128 MDU proposed an expense of $1,795,578 for Taxes Other Than Income. MCC's witness proposed net adjustments decreasing this category of expense by $104,531. The bulk of MCC’s

adjustment flowed from changes in the Ad Valorem Taxes (associated with its rejection of post test-year plant additions), Payroll Taxes (associated with its modification of payroll expenses), and MPSC/MCC Taxes (associated with the revenue change).

129 Each of MCC's proposed adjustments were dependent upon Commission acceptance of the MCC's position. The Commission rejected the MCC's proposal not to include post-test-year plant, therefore, the proposal to modify the Ad Valorem Taxes is rejected. The Commission adjusted MCC's proposed payroll expense reduction, included in O&M, and this action modified the MCC's calculated payroll taxes. The MCC/PSC tax is revenue dependent, and, therefore, dependent upon the final revenue amount authorized by the Commission in this Order.

130 The Commission finds, adjusting MDU's Taxes Other Than Income for the decisions made in this order, that MDU should be allowed expenses of $1,763,593.

Income Taxes

Pension Expense Deduction

131 During the test year MDU's pension plan was over funded and, therefore, under the IRC, MDU was not entitled to take a tax deduction for pension contributions. MCC proposed that MDU be ordered to take a tax deduction, for ratemaking purposes only, for the pension expense included in the MDU's pro forma revenue requirement. MCC asserted that MDU's present treatment of the pension expense accrual in the revenue requirement offsets a reduction to current taxes by an increase in deferred taxes (without a rate base offset for the deferred taxes). MCC argued

that ratepayers are providing revenues to the Company to pay a "phantom" expense (pension) without receiving any tax benefit.

132 MDU countered MCC's proposal through the testimony of A. J. Fiest. Fiest stated that MCC is correct in its assertion that none of the test year pension contribution was tax deductible. However, he describes MCC's characterization of the accounting afforded pension expense as totally in error. Fiest states "Since no portion of the pension contribution was tax deductible in 1994, the Company experienced an <u>increase</u> in current income tax expense which was offset by an equivalent decrease in deferred income tax expense, with no effect on the revenue requirement as a result of this action. Therefore, the Company's treatment of this item in its revenue requirement is exactly the opposite of that described by Mr. Clark."

133 Based on the testimony provided by Fiest, it is clear to the Commission that MDU is properly accounting for the taxes associated with the pension expense. The Commission finds that MCC's proposed ratemaking income tax deduction should be rejected.

134 Income tax expense is dependent upon the final determinations of the Commission in this Order. The calculated income tax expense for MDU is shown in para. 135 (immediately below) of this Order.

<u>Revenue Requirement</u>

135 The Commission finds that in order to produce a rate of return of 10.913 percent on MDU's average original cost depreciated rate base, MDU will require additional annual revenues in the amount of $1,008,687 from its Montana gas utility

operations. MDU's accepted test year pro forma operating revenues, expenses, and rate of return are summarized as follows:

	At Present Rates	At Proposed Rates
Revenues	$48,402,028	$49,410,715
Dollar Increase		$1,008,687
		2.01%
O & M Expense	42,900,709	42,900,709
Depreciation	1,781,674	1,781,674
Taxes Other Than Income	1,760,969	1,763,592
Income Taxes	5,515,088	5,911,351
Deferred Income Taxes	-5,110,756	-5,110,756
Amort of pre-1974 gain on debt	-14,000	-14,000
Total Deductions	46,833,684	47,232,570
Operating Income	1,568,344	2,178,145
Rate Base	19,959,181	19,959,181
Return on Rate Base	7.858%	10.913%

COST OF SERVICE AND RATE DESIGN

Introduction

136 As general information, the last thorough analysis of MDU's gas cost of service and pricing occurred in Docket No. 88.11.53. MDU's next most recent gas cost of service filing (relative to the present docket), Docket No. 92.2.9, prompted by Order No. 5490, Docket No. 88.8.23, et al., was suspended pending FERC Order 636, and eventually combined with several other MDU gas-related dockets into Docket No. 94.9.39 for settlement

purposes.[12] Specific references to these dockets and others, if any, will be included where necessary.

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[12] See, n. 1.

137 The following table provides an abbreviated version of the model used by the PSC to develop and organize cost of service testimony.[13] With it costs are first organized by function. Several cost functions include production (costs to secure gas supplies), distribution, and customer. Related to the gas supply (production) function are transmission and storage. After functionalizing, costs must be related to the actions that cause their incurrence (referred to as “classification”). Most costs are classified as either energy, demand, or customer related based on how a utility must respond to customer demands. Classified costs are then allocated to customer classes according to annual throughput, peak day demand, or customer numbers. The model serves to organize cost of service methods and testimony, the actual methods used to estimate and finally allocate costs are discretionary.

Cost of Service and Rate Design Model

Cost Functions (1)	Cost Classification (2)	Cost Allocation (3)	Reconcile and Moderate (4)	Rate Design (5)
Gas Production, Storage and Transmission	Energy, Demand	Annual Throughput, Peak Day	Uniform Percent or Other - e.g., Market Based	$per/dkt
Non-gas distribution	Energy, Demand	Annual Throughput, Peak Day		

[13] The table is based on ARM 38.5.176, which directs how cost of service shall be presented and analyzed and explains cost studies to be filed and how they shall be organized.

Non-gas customer	Customer	Customer Classes		$/month/ customer

138 Since marginal cost of service revenue requirements normally do not equal the allowed revenue requirement, cost of service must also be reconciled with the allowed revenues. A uniform percent adjustment is the most often used reconciliation method. If unacceptable rate changes result, the reconciled revenue increases are moderated to mitigate adverse rate impacts. Prices must eventually be set to recover the allowed revenue requirement.

139 For sales customers gas pricing often involves a two-part tariff consisting of energy (e.g., $/dkt) and base rates (e.g., $/month/customer). More complex pricing may be required for unbundled transportation services.

140 MDU's sales tariffs include Rate 60 - Firm Residential; Rate 70 - Firm General Service (commercial); Rate 71 - Small Interruptible (commercial); Rate 85 - Large Interruptible (industrial). MDU’s transport tariffs include Rate 81 - Small Interruptible (commercial); Rate 82 - Large Interruptible (industrial); and Rate 84 - Firm transport. Other rate classes include Rates 62 and 72 - seasonal residential and commercial firm sales; Rate 80 - electric generation interruptible transport; Rate 93 - special gas service; and Rate 99 - propane service. Other MDU tariffs include: Rate 100 - conditions for service; Rates 119 and 120 - line extension policies for interruptible and firm customers respectively; and Rates 87 and 88 - MDU's gas cost of service tracking procedure.

Cost of Service

141 In this matter only MDU and MCC testified on MDU's cost of service. Witnesses Robert D. Greneman and Tamie A. Aberle testified on MDU’s behalf (direct and rebuttal). Witness George L. Donkin testified on MCC’s behalf.

142 Greneman testified that MDU's goal is the efficient use of gas. To him, if prices are adjusted to marginal cost of service, both production and allocative efficiency goals are attained and MDU’s stated goal will be achieved. In response to data requests, he expanded on MDU’s pricing policy goals, adding that cost of service should include objective estimates for unbundled service offerings.

143 Donkin’s pricing policy objectives include energy conservation, efficient use of facilities, rate continuity, and revenue stability. He stressed that cost of service based prices are important to avoid cross subsidies.

144 Aberle and Greneman analyze cost of service from different perspectives. Although Greneman asserts having studied the long-run marginal cost of service for gas and non-gas supply functions, his study includes embedded costs. Aberle testified that Greneman’s marginal cost of service study used certain of her embedded cost of service results. Together, MDU’s marginal and embedded cost of service results were the basis of the MDU rate design proposals in this docket.

145 Donkin also testified on appropriate costing methods for MDU’s gas distribution system. Although his analysis of MDU’s embedded cost of service study focused on non-gas costs,

Donkin compared the Atlantic Seaboard cost method[14] to the straight fixed variable (SFV) method[15] in FERC Order 636.[16] Donkin asserted that the SFV method is required (at the federal level) in pipeline rate design but not in how costs are allocated.

146 Donkin compared embedded and marginal cost of service study methods, maintaining that because the provision of utility service is largely a supply of joint products, an embedded cost of service study attempts to allocate joint costs among classes and, in contrast, a marginal cost of service study analyzes how costs change when one more, or one less, unit is produced. He added that a marginal cost of service study is time-dependent and can be viewed from short-run or long-run perspectives. He also testified that MDU's long-run marginal cost study is flawed for not having focused on the incremental change in total costs of increasing or decreasing gas "sendout." After stating long-run

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[14] 11 FPC 43 (1952), where capacity costs serve both peak and annual customer requirements.

[15] SFV removes fixed costs from the commodity component of rates.

[16] Intended as a general reference to a series of FERC orders 636, commencing in 1992 and pertaining to pipeline restructuring rules arising out of FERC Docket No. RM91-11.

marginal costs are not viable, he described an intermediate-run cost study.

Gas Supply Costs

147 Greneman's gas supply costs include the commodity cost of gas and certain Williston Basin Interstate Pipeline (WBIP) transport costs that vary with increased purchases of gas or increased gas demand per day (thousand cubic feet/day or Mcfd).[17] He excludes other gas supply costs (e.g., storage and transport) if they do not vary with increased demand.

148 Greneman derived gas supply long-run marginal costs from MDU’s tracker and allocated such costs to firm and interruptible sales. His long-run marginal cost for firm sales of $3.042/dkt included tracker-related commodity and demand costs. For interruptible sales, his long-run marginal cost equaled $1.919/dkt. The higher firm sales value included tracker demand costs.

149 After analyzing the tracker costs in MDU’s long-run marginal cost study Donkin included the commodity cost of gas in his study. His marginal gas cost is $1.92/dkt. Even though MDU pays WBIP for tracker-related demand and reservation costs, he excluded WBIP's Maximum Daily Delivery Quantity (MDDQ) charges, arguing that MDU can not avoid paying such demand (or

[17] Natural gas consumption on MDU’s system is measured in dekatherms. One dekatherm (dkt) equals one million British thermal units (Btu’s).

reservation) charges in either the short-run or long-run, such costs not apparently being variable. His testimony is founded on the belief that WBIP likely has excess capacity on the relevant parts of its system and there is little demand for off-peak capacity in the capacity release market.

150 Donkin’s inclusion of embedded storage-related costs reflects his position that storage benefits all of MDU’s firm and interruptible customers on a year-round basis. He argued that MDU’s approach of only allocating such costs to peak-day customers is not consistent with Aberle’s admission that interruptible transport customers make use of storage facilities to balance their demand, they just do not pay a separate rate for these costs. He classified storage costs as 50 percent energy and 50 percent capacity, the former allocated on the basis of annual throughput, the later allocated based on peak demands.

151 Aberle, in rebuttal, criticized various aspects of Donkin’s cost of service testimony. Although she agreed with Donkin’s asserted focus on non-gas costs, she found that Donkin, in fact, did not do so. According to Aberle, Donkin’s logic for focusing on non-gas costs is tied to an erred assumption about the relation of sales and transport loads. Whereas Donkin argued that MDU’s business has shifted since 1993 from retail to transport, Aberle testified that MDU’s transport throughput declined, in percentage terms, since 1993.

152 In the context of distribution costs, Aberle criticized Donkin’s SFV rate design testimony. She asserted that pricing a local distribution company’s (LDC) rates using the SFV method eliminates controversy because “all” fixed costs would be recovered through demand and customer charges.

153. Aberle criticized Donkin’s allocation of storage costs to transport customers. She asserted that Donkin artificially allocates storage costs, apparently just to transport customers, as a result of wrongly assuming “no-notice” service is available at all delivery points onto MDU’s distribution system.[18]

<u>Non-Gas Supply Costs</u>

Marginal Distribution Cost of Service

154. Greneman based his marginal distribution cost of service analyses on determining the incremental cost of service and expenses associated with providing an additional peak-day Mcf of natural gas capacity over MDU’s distribution mains and related system facilities over the 10-year period 1995 through 2004. His analyses resulted in a total marginal cost of service of distribution of $12.44 per peak day Mcf (1997 dollars).

155. Donkin, on the other hand, asserted that MDU's analyses focuses too much on the cost of service of connecting new customers to the system rather than the marginal cost of service of distribution capacity. His analyses resulted in a total

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[18] Although Mr. Greneman includes MDDQ related transport costs but excludes storage capacity and deliverability costs in his marginal cost study, when MDU was asked what costs would be reallocated when a sales customer converted to transport, MDU included both transport and storage costs (MDU Data Response No. MDEQ-8(C)).

marginal cost of service of distribution of $1.63 per peak day Mcf.

156. Greneman explained that his marginal costing methodology is in accordance with standard industry practice and in accordance with MDU's last two marginal cost of service studies filed with the PSC.

157. According to Greneman, the marginal cost of service of distribution capacity includes the following components: capital cost; cost of service allocations for general and common (G&C) plant, operation and maintenance (O&M), and administrative and general (A&G); taxes other than income; revenue-related taxes; and working capital requirements.

158. Greneman's analysis includes several steps. First he estimated an average peak-day load growth of 1243.3 Mcf/year over the next 10 years on MDU's system. He then reviewed MDU's budget projections for planned distribution system capital expenditures over the next 10 years and determined that $667,634 (1997 dollars) are growth-related. According to Greneman these expenditures consist of two components: a growth-related component of line extensions; and costs associated with the "Northwest Loop Project", MDU's only specific project planned at this time to increase the capacity of its backbone system. His total demand-related distribution investment per additional Mcfd of distribution capacity is $53.46 (1997 dollars).

159. Greneman then added a G&C plant allocation and applies a nominal 14 percent carrying charge to convert the sum into an annual carrying charge. Additional annual costs associated with supporting, operating, and maintaining the distribution system

were added to the annual carrying charge to derive MDU's marginal distribution capacity cost of $12.44.

160. Greneman classified this cost as demand and allocated it to the Residential and Firm General classes based on those classes’ peak demands. He allocated these costs to interruptible classes based on a 100 percent load factor.

161. According to Donkin, MDU's cost of service studies are flawed because they allocate too much of MDU's total non-gas costs on the basis of the number of customers in each class, which causes too many of MDU's non-gas costs to be assigned to small-volume gas consumers in Montana. He believes the major focus of a marginal cost of service analysis for MDU, which experiences little growth in customers from year to year, should be the marginal distribution capacity costs, not the marginal cost of adding new customers.

162. Donkin's distribution capacity cost of service calculation, like Greneman's, began with determining capital costs, annualizing these costs, and then adding allocations for O&M, taxes, and working capital. Donkin excluded both G&C plant and A&G allocations from his calculations. In response to data requests, Donkin stated that there is very little relationship between an LDC's incremental investments in G&C or A&G expenses and incremental changes in the LDC's peak day send out.

163. Donkin's method of calculating the capital cost of distribution capacity on MDU's system is significantly different than Greneman's method, in that it is based on MDU's actual recent distribution investment experience. His method results in much lower capital costs, which generally accounts for the large disparity in the parties' marginal distribution cost estimates.

He developed the capital cost of distribution by summing the costs of various distribution projects completed on MDU's system during the period 1988 through 1994. These costs were then divided by the sum of the capacities of these projects. The result, $10.61, was converted to the annual amount using the same (nominal) carrying charged used by Greneman.

164. Donkin also used the same allocation factors for O&M, taxes, and working capital as Greneman, but since his capital costs differ from Greneman's, his O&M, taxes, and working capital allocations also differ. His final marginal cost of distribution capacity on MDU's system is $1.62. He first multiplied this cost by MDU's peak day throughput which results in a total marginal cost of distribution capacity on MDU's system of $138,796 at system peak. He then classified this cost as 50 percent distribution demand and 50 percent distribution throughput. Before allocating these costs to various customer classes, he reconciled these components to MCC's proposed embedded revenue requirements.

165. Greneman disagreed with Donkin's assertion that MDU’s marginal cost of service study is too focused on the cost of adding new customers. He believes his study does not focus more or less on any particular cost component. He also disagreed with Donkin's assertion regarding the role that marginal customer costs should play in a general rate proceeding.

166. Greneman also claimed that not only is Donkin's marginal capital cost estimate, which is based on historical costs, out of date, his methodology is inconsistent with the PSC’s Order No. 5399d in Docket No. 88.11.53. However, he stated that Donkin's and his conclusions are the same. That is, since

MDU's system generally has adequate distribution capacity, the price signal associated with this capacity is less prominent than for other cost considerations.

167. Finally, Greneman criticized Donkin's exclusion of G&C plant and A&G expenses from the analyses. He stated that these costs are generally recognized to be related to the size of the utility, sales, number of customers, and peak demand.

Marginal Customer Costs

168. Both MDU's and MCC's marginal customer cost analyses include many of the same steps and components as their distribution cost analyses. The primary difference between MDU's and MCC's analyses is in the customer-related marginal capital cost component. In addition, MDU's analyses included both a G&C plant and an A&G cost allocation, while MCC's analyses excluded these components. Both parties derived marginal customer costs for MDU's primary customer classes.

169. Greneman's customer costs included essentially the same components as his distribution costs, i.e., capital costs, G&C plant, O&M, A&G, Taxes, and Working Capital requirements, plus an additional component, Customer Accounting Expenses. The details of the methodology used to develop these components are similar to those used in Greneman's distribution cost analyses.

170. According to Greneman, MDU's capital customer costs are based on the present installed cost of a typical main extension, service stub, and meter/regulator associated with each customer addition. G&C plant, O&M, A&G, taxes, and working capital allocations were developed by Greneman similarly to the way these same components were developed in his distribution cost analyses.

171. According to Greneman, customer accounting expenses include meter reading, customer accounting and billing, customer service and informational expenses, and sales expenses.

172. Donkin's marginal customer cost calculations are the same as Greneman's with the following exceptions. His analyses excluded investments in main extensions and service stubs and cost allocations for G&C plant and A&G cost allocations.

173. As in his rebuttal to Donkin's exclusion of G&C and A&G costs in marginal distribution cost analyses, Greneman also disagreed with Donkin's exclusion of these costs in marginal customer cost analyses. He agreed that, although G&C and A&G costs may not increase in direct 1:1 correspondence with increases in demand, these costs are generally recognized to be related to the size of the utility, and the size is related to sales, numbers of customers, and peak day demand. Therefore, to Greneman, these costs cannot be disassociated from marginal costing.

Embedded Cost of Service

174. According to MDU, its embedded cost of service study was used to develop several of the functionalization and classification relationships used in its marginal cost of service study. MDU also used its embedded cost of service to mitigate those residential rate increases justified on the basis of its marginal cost of service study.

175. According to MCC, embedded cost of service studies, are a calculation of a gas utility's historical costs, including all of the costs used to support the allowed revenue requirement. These studies distribute these costs to customer classes based on

cost incurrence or cost responsibility considerations. MCC asserts that since the supply of gas utility service is largely a supply of joint products, embedded cost of service analyses represent an attempt to allocate among the rate classes the joint costs incurred by an LDC to provide gas service.

176. Aberle prepared MDU's embedded cost of service study. Her results are presented in Statement L of MDU's filing. Statement L also contains numerous reports which detail how various expenses, adjustments and revenue requirement components are allocated among customer classes. The reports include: Plant in Service; Accumulated Reserve for Depreciation; Construction Work in Progress; Operating Revenue; Operation and Maintenance Expense; Depreciation Expense; Taxes Other Than Income; Deferred Income Taxes; Income Taxes; Working Capital; Investment Tax Credit Balance; Rate Base; Pro Forma Adjustments to Operating Income; Pro Forma Adjustments to Rate Base; and cost of service by Component.

177. Donkin believes that MDU allocates an unreasonably high percentage of its non-gas costs on the basis of the number of customers, resulting in excessive non-gas costs being assigned to small volume and low load factor customers (primarily the residential class). He explained that in recent years, due to marketability risks, it has been common for local distribution companies (LDC) such as MDU to attempt to recover a greater portion of non-gas costs through fixed customer charges for residential and small commercial customers who typically have few viable short-run alternatives to natural gas.

178. Donkin alleged that MDU's embedded cost of service study misallocates the cost of Distribution Mains, Service Lines,

Industrial Measuring & Regulating Station Equipment plant and costs, and A&G costs.

179. Donkin disagreed with MDU's method of allocating the embedded costs of distribution mains (about $17.3 million). MDU allocated 42 percent of distribution mains on a customer basis, and 58 percent on the basis of demand. According to Donkin, an efficient distribution system optimizes the cost-effective delivery of gas supplies to end-users on the basis of annual and peak-period system requirements, not on the basis of the number of customers served. He used the following example to show that gas lines are installed and sized to meet customer loads and not customer numbers: a distribution line would be the same size whether it served 20 residential customers each having a coincident peak demand of 1 Mcf, or 1 industrial customer with a coincident peak demand of 20 Mcf. He prefers to allocate 50 percent of mains costs on the basis of 2-day coincident peak demand and 50 percent on the basis of annual throughput for each customer class.

180. Donkin disputed MDU's method of allocating 100 percent of its total investment in service lines as customer-related. He prefers to allocate only 50 percent on the basis of the numbers of customers in each class, 25 percent on the basis of annual throughput, and 25 percent on the basis of 2-day coincident peak volumes.

181. Donkin also disagreed with MDU's method of allocating its Industrial Measuring & Regulating Station Equipment plant and costs. MDU's method results in a portion of these costs being allocated to customer classes other than industrial customers. Donkin’s position is that it is inappropriate to allocate any

portion of facilities designed and installed to serve industrial sales or transportation customers to any other class than industrial. In his study, all Industrial Measuring and Regulating Station Equipment plant and costs were allocated directly to the Industrial classes.

182. Donkin also disputed MDU's method of allocating A&G expenses, which is based on customer numbers. He claimed that customer numbers can increase or decrease over a wide range without changing A&G expenses. Accordingly, in his study, none of these costs are allocated to customer classes on the basis of customer numbers.

183. Aberle, in rebuttal, criticized Donkin's testimony regarding distribution mains cost allocations, service line cost allocations, and A&G cost allocations. She disagreed with his method of allocating the costs of distribution mains, citing to a June 1989 NARUC "Gas Distribution Rate Design Manual" in support of her argument. She claimed that allocating distribution mains costs to the customer function is appropriate since the distribution mains exist because customers exist. She also provided data that reveals a correlation between customer numbers and distribution mains investments.

184. Aberle stated that since service line costs vary directly with the number of customers served rather than the amount of utility service supplied, these costs are clearly customer related. She believes that Donkin's method of allocating these costs is incorrect.

185. Aberle criticized Donkin's method of allocating A&G costs. She explained that his assertion that customer counts may fluctuate over a wide range without a change in A&G expenses is

not supported by any analysis. She claimed that these expenses are incurred for the overall support of all functions, including customers sales and distribution expenses, and clearly vary with a change in the numbers of customers.

<u>Commission's Cost of Service Analyses and Decisions</u>

186. The Commission shares MDU's and MCC's concerns regarding cost-based pricing. For policy reasons, the Commission cannot entirely base decisions on costing alone. The testimony in this docket continued past debates over non-gas costs, but did not thoroughly estimate the true cost of service, as there was minimal testimony on gas costs. The Commission approves many of MDU's rate spread, rate design, and pricing proposals, but finds that MCC's counsel against rebalancing in this docket is sound. Another general gas docket, perhaps one combined with an MDU tracker as means of addressing gas costs, must address the true and total cost of service.

187. In addition to other MDU witnesses MDU's president, Ronald D. Tipton, testified at hearing before the PSC. The Commission agrees with Tipton's testimony that price is probably the most important matter in today's gas marketing environment. The importance of price may echo Tipton's earlier testimony asserting it is critical to establish natural gas rates that reflect the "true cost" of serving distribution level customers. Furthermore, price matters more today then in the past, when markets for gas were less competitive and less open. In today's environment prices must be based on a sound revenue requirement and, as Tipton emphasized, the "true cost" of service. The Commission has determined that the non-gas revenue requirement

increase in this docket is sound. The Commission also now determines that recovering the increase entirely from the residential class is appropriate.

188. For their respective price levels and rate design proposals, MDU and MCC each imputed costs to MDU’s tariffed prices. From what can validly result from analysis of MDU’s and MCC’s respective cost testimony, the Commission approves many of MDU’s proposals in this docket, including rate increases and certain rate design and pricing proposals. However, the Commission does not find that the testimony and argument in this docket is sufficient to also justify a rebalancing of MDU’s rates.

189. Consistent with Tipton’s concern that prices reflect the true cost of service the Commission will not rebalance rates in this docket. The Commission is neither in opposition to a rebalancing nor wed to costing as the sole reason to (or not to), change prices. However, other policy criteria must also be considered and the focus on non-gas costs in this docket simply raises valid concerns with rate rebalancing. In addition to recovery of non-gas costs, prices must also recover fair and equitable shares of gas costs. If pricing is important today, it is of crucial importance that prices, in relatively more competitive markets, receive deliberate and unobstructed cost analyses. It would not serve the public interest to rebalance based on non-gas costs when a majority of MDU’s costs are gas related.

190. The limited gas cost testimony in this docket leaves the Commission with more questions than answers. It has never been sufficient for a party to simply assert that a cost, such as

transport or storage, is valid on marginal-cost grounds and then expect the same cost to be approved by the Commission. Yet, MDU basically asserts transport costs from MDU’s tracker are marginal and MCC basically asserts embedded storage costs are relevant, thorough analysis not being part of either assertion. Although the Commission withholds any rebalancing until gas costs are thoroughly analyzed in a future docket, it is time to consider a change in how those cost issues should be debated.

191. MDU bifurcated its gas and non-gas cost testimony. MDU’s marginal cost consultant considered some gas costs as marginal. MCC testimony focused on non-gas costs. In turn, MDU supported MCC’s focus. The Commission finds that for purposes of this docket the non-gas cost testimony of MDU and MCC is necessary to allocate the non-gas revenue increase. However, the Commission finds that marginal gas costs must be part of cost of service for rate design. In a past MDU docket (No. 88.11.53, Order No. 5399b, paras. 193-195) marginal gas costs were based on WBIP's tariffs. MDU’s and MCC’s non-gas cost focus in this docket is insufficient to rebalance rates.

192. On marginal distribution costs the Commission’s decisions combine elements of both MDU's and MCC's analyses. First, the Commission prefers MCC's marginal capital cost calculation of $10.61 (compared to MDU's $53.46). MCC's capital cost analysis is based on historical data and is similar to the analysis the PSC approved in Docket No. 88.11.53 (Order No. 5399b, para. 196). The Commission agrees with MDU that using historical data might be somewhat inconsistent with the directive in Order No. 5399b, paras. 16-19 (to use data that will result in avoided costs). The Commission commends MDU for using forecasted

costs in its analysis in this docket. However, the Commission agrees with MCC that MDU's results rely too heavily on investments in mains and service stubs associated with connecting individual customers.

193. In particular, the Commission questions MDU’s estimates attempting to represent costs associated with the demand component of main extensions (Column 3, MDU's Ex. RDG-3). First, it is not clear that any costs associated with main extensions should be included in a marginal distribution cost analysis. Second, the costs in the referenced column appear to be based on constructing approximately 800 main extensions per year and that is inconsistent with MDU’s forecasted construction of about 100 extensions per year (MDU response to PSC-40c). As a result, this component of MDU's capital distribution cost analysis appears overstated.

194. Other than the initial capital cost calculation, the two parties' marginal distribution cost of service analyses are similar except that MCC excludes allocations for G&C plant and A&G expenses. The Commission finds that, since MCC failed to provide any persuasive evidence that these allocations should not be included, they should be included using MDU's proposed allocators. Using MCC's capital cost of distribution and MDU's proposed G&C and A&G allocators (as well as MDU's carrying charge and other allocators that were not contested), the marginal cost of distribution on MDU's system is $2.47/Mcfd.

195. On marginal customer costs, both MDU's and MCC's analyses include many of the same steps and components of their respective distribution cost analyses. However, their analyses and results differ. Again, the primary difference is with the

marginal capital cost component. In addition, MDU's analyses include both a G&C plant and an A&G cost allocation, while MCC's analyses exclude these components.

196. As with the marginal distribution cost of service, the Commission's decisions on marginal customer costs combine the analyses of both MDU and MCC to derive the marginal customer costs of service for MDU's various customer classes. First, the Commission approves MCC's capital costs for each class. As opposed to MDU's capital costs, MCC's costs exclude investments in main extensions and service stubs. This is consistent with past Commission decisions to exclude these costs, rationale being well documented in other orders, including Order No. 5399b, Docket No. 88.11.53, para. 119.

197. To MCC's capital costs, the Commission again adds allocations for G&C and A&G, for the same reasons similar allocations were included in the marginal distribution cost analysis. The Commission’s final marginal customer costs are as follows. But first the Commission takes this opportunity to alert both MDU and MCC to the inconsistent carrying charges used in this docket (nominal) relative to those used and approved in past dockets. Relative to real carrying charges, MDU’s nominal carrying charges will exaggerate the distribution and customer costs approved in this docket. The Commission expects real carrying charges will be used to annualize costs in the future.

Customer Class	Cost/Month
Residential Class (Rates 60 & 62)	$8.01
Firm General Sales (Rates 70 &	$19.65

72)	
Small Interruptible Sales (Rate 71)	$72.53
Small Interruptible Transport (Rate 81)	$157.92
Large Interruptible Sales and Transport (Rates 82 & 85)	$1,197.33

Rate Reconciliation and Moderation

198. Once a marginal cost of service study is completed, the total marginal costs must be compared to the allowed revenue requirement. If the two cost studies' results differ (total marginal costs compared to allowed revenues), then reconciliation must occur. If, in the Commission's estimation, reconciled revenue requirements violate principles of acceptability and stability, then the reconciled results will be moderated.

199. Greneman supplied MDU's reconciliation testimony. From Exhibit RDG-14, the disparity between the company's total requested revenue requirement ($49,348,141) and the total marginal costs ($53,613,602) is evident. By means of an equal-percent reconciliation Greneman reduced each class's total marginal costs by multiplying by 92.04 percent.

200. Throughput assumptions (gas sales and transport and customer numbers) impact reconciliation. Based on other MDU witnesses' testimony, Greneman excluded sales volumes and customer (access related) costs for Rates 84 and 85. MDU witness R. J. White testified on MDU's actual and expected customer attrition and then excluded volumes for Cenex and Conoco and

Western Sugar.[19] Tipton testified that the Western Sugar load loss was anticipated. White also testified that because five customers will install propane/air systems it is correct to recognize the change and shift the loads from Rate 70 (Firm General Service) to Rate 81 (Small Interruptible Transport).

201. Donkin's reconciliation differs. He found that regulatory and structural changes in the gas industry call for a different reconciliation method. To Donkin the past practice of using an equal percent reconciliation, which Greneman used, is no longer appropriate. With transportation representing a significant portion of MDU's business, he Donkin argued that reconciliation should focus on non-gas costs.

202. Donkin's reconciliation involves cost allocations. First, distribution throughput costs were allocated to classes based on the normalized throughput in MDU's embedded cost study. Second, after he classified 50 percent of distribution capacity costs to demand, to reflect peak day requirements (the other 50 percent is classified to throughput), the demand costs were allocated to classes based on peak day demands with an imputation to interruptible customers at a 100 percent load factor. Third, while he allocated marginal customer costs based on customer

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[19] Although raised in the context of revenue requirements this testimony is noted here due to the apparent linkage to cost of service and rate design. White's rebuttal addresses MCC's opposition to certain of these load adjustments.

numbers, he held these costs constant and reasserted the need to focus costing on distribution.

203. Donkin does not use the same throughput, or billing determinants, that MDU used. He used normalized 1994 throughput volumes for all rate classes. Because these volumes exceed MDU's, he allocated the excess of MCC's over MDU's volumes based on MDU's pro-forma sales and transport volumes. Thus, and apparently like MDU, he also assigns demand costs to interruptible customers. The below discussion on moderation contains Donkin's final proposals on allocating non-gas revenue increases.

204. As in most cases the cost of service studies in this docket produce results that must be moderated. Aberle's moderated rate impacts assume MDU receives a $2.1 million revenue increase. Her moderation attempts to ease the impacts on residential customers and at the same time "minimize the existing subsidization of the residential class by all other classes." With these goals, she did not decrease the large interruptible industrial (sales Rate 85) class's rates. Second, she applied an 8.4 percent revenue decrease to the firm general service (sales Rate 70 & 72) and small interruptible classes.[20] She moderated the residential class's (Rates 60 & 62) increase 12 percent.

205. Donkin invoked the rate making principles of rate continuity and gradualism and provided general argument on how the Commission ought to flow through revenue increases and decreases. First, he proposed that the residential and large

[20] This amounts to a 4.9 percent decrease for interruptible sales Rate 71 and an 8.7 percent decrease for interruptible transport on Rates 80 and 81.

interruptible classes (Rates 60, 62, 82 and 85) absorb 100 percent of any non-gas revenue increase, such increase being on an equal percentage basis.[21] With MCC's proposed revenue increase, he recommended moderate shifts in non-gas revenue responsibilities. He advised freezing the general service and small interruptible non-gas revenues. To Donkin, if the Commission were to order a $2.0 million increase, the residential Base Rate "would" rise by the same increase in non-gas revenues.

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[21] Based on class rates of return, Donkin finds negative returns for the residential and large interruptible customer classes.

206. Second, if the Commission were to order a decrease in non-gas revenue requirements, Donkin asserted the residential and large interruptible non-gas revenues should be frozen and the entire decrease flowed through proportionally to general service and small interruptible customers.[22]

207. Aberle's rebuttal asserted that Donkin's cost of service study and Clark's (MCC revenue requirements witness) total cost of service appear independently produced in that they do not use the same throughput volumes. She added that a class cost of service study must produce overall cost of service. She also asserted that MCC improperly imputes demand to interruptible customers.

208. Aberle held that MCC's ultimate allocation of revenues, based on a 3 percent increase in non-gas revenues, is unclear and will frustrate efforts to meaningfully set class cost of service. Aberle criticizes MCC's increased allocation of costs to the large industrial class. She testified that these costs will not be recovered given the "flexed" transport ceiling rate. Aberle also testified that MCC's misstated non-gas revenue requirement should equal $16,409,278.

209. Aberle criticized MCC's proposal to cap the residential class increase. She argued that this proposal violates Donkin's own principles. She added that MCC distorts the facts by alleging MDU proposed a 41 percent increase in the residential class's rates.

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[22] "proportionally" appears in relation to current revenues.

Commission Reconciliation and Moderation Decisions

210. The Commission's spread of the revenue requirement increase in this docket is simplified by the nature and outcome of the parties' cost of service studies and testimony. This is not to mean that parties' cost of service in this docket was simple or thorough. MDU's non-gas marginal cost study justifies a revenue increase for just the residential class (MDU response to PSC-127, Attachment A). MCC states that all of the class cost of service studies support increasing the residential class revenue requirement (Tr. p. 134). Therefore, MDU's proposal to pass through the entire increased non-gas revenue requirement to the residential class is approved. MCC's proposal to spread the increase equally to residential and large interruptible classes (Rates 82, 85) is not clearly supported by the non-gas cost evidence in this docket. The Commission finds that the focus on non-gas costs is minimally acceptable for purposes of deciding the merit of cost studies and the allocation of their results. Future revenue increases must be supported by a deliberate and unobstructed analysis of gas and non-gas costs.

Rate Design

211. In regard to Firm Residential Sales (Rates 60 & 62), although MDU requested an overall revenue increase of about 4.4 percent, Aberle proposes an average increase in revenues of 12 percent for Residential Rates 60 and 62.[23] That average

[23] In other words, if MDU's requested revenue increase of about $2 million is granted, the residential class would receive all of the increase, plus about an additional $1.5 million

increase also varies by the level of consumption. Residential customers with small meters would receive a 13.5 percent increase while customers with large meters would receive about a 10 percent increase.

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increase related to revenue decreases for other classes. The residential class’s total increase would be about $3.5 million.

212. On the basis of marginal costs, Aberle proposed raising Base Rates. For small customers the Base Rate would rise from $4.50 to $6.50 per month. For large customers the Base Rate would rise from $10.00 to $13.00 per month. She also proposed replacing the uniform rate structure with a declining-block rate structure.[24] The seasonal rate difference Rate 62 reflects MDDQ costs of $1.117/dkt. Rates 60 and 62 would also be subject to MDU's Weather Normalization Adjustment.

213. Donkin opposes increased residential Base Rates. In reference to embedded costs he defends a maximum Base Rate of $4.50. He notes that a lower Base Rate avoids lowering the commodity charge. With a $2.0 million revenue increase, however, the Base Rate "would" rise to $5.13.

214. While his testimony only includes exhibits with rate elements for the other classes, Donkin provided general testimony on rate design. For each of MDU's tariffs he recommends a two-part rate design that includes a Base Rate and a "uniform commodity charge." For other than the residential class he has no recommendations regarding MDU's proposed Base Rate increases. He uses the current Base Rates to design rates. For sales customers he also testifies that the gas cost component should be equal, and the non-gas component should reflect the non-gas revenue requirement of each sales class after accounting for Base Rate revenues.

215. In rebuttal, apparently directed to all classes, Aberle finds MCC's rate calculations laden with errors. Since MCC did

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[24] With the declining block rate structure, MDU would charge more ($.50/dkt) for each of the first five dkt/month than for all additional dkt/month.

not address MDU's declining-block rate structures (residential or general service) she asserts they should not be rejected. As evidence that the firm general service class subsidizes the residential class she computes a 16 percent difference between the average annual bill for a residential customer and the bill the customer would otherwise be charged if served off the firm general service tariff.

216. In regard to Firm General Service Sale (Rates 70 & 72) Aberle stated that the firm general service class should receive an 8.4 percent decrease in revenues. As with the residential firm sales tariffs, she proposed increased Base Rates and a declining-block rate design with a 10 dkt breakpoint. For small metered customers the Base Rate rises from $8.00 to $10.00 per month. For large metered customers the Base Rate rises from $17.00 to $25.00 per month. As with the residential class, bill impacts depend on a customer's gas demand. Rates 70 and 72 are also subject to MDU's Weather Normalization Adjustment.

217. In regard to Small Interruptible General Service Sales (Rate 71), based on marginal costs, Aberle proposed raising the Base Rate from $35.00 to $100 per month. She also proposed to flexibly price service between ceiling and floor commodity rates ($/dkt).[25] The ceiling reflects the fully allocated non-gas commodity rate plus gas costs. The floor reflects MDU's proposed floor for transport service plus the gas commodity charge applicable to all customers. MDU proposes to eliminate the 6,000/dkt annual minimum on this tariff.

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[25] The Commission first considered and granted flexible pricing in MDU Docket No. 87.01.08; however this earlier approval was for transport, not sales rates.

218. Although not contained in any direct testimony, MDU also revised the terms and conditions for standby service on its interruptible tariff. The revision would allow MDU to automatically shut off gas to a customer (the additional issues section of this order reviews testimony that MDU was ordered to file on this tariff change.) Tipton testified that all of MDU’s interruptible rates (Nos. 71, 81, 82 and 85) are too high.

219. DEQ witness, Robert P. Frantz, disagreed with MDU’s assertion that interruptible rates are too high.[26] He is troubled with the relation between MDU’s firm and interruptible transport rate levels, opposes retention rates and advised linking interruptible rates to the benefits conferred.

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[26] DEQ testimony is on the reserved interconnect issue, but is considered as part of the record for the main case insofar as related rates are concerned.

220. Regarding Large Interruptible General Service Sales (Rate 85) Aberle did not propose to decrease this class's rates.[27] Aberle proposes increasing the Base Rates from $265 to $1,150 per month, while decreasing the gas rate from $4.06 to $2.23/dkt before removing the tracker adjustment (the tracker adjustment amounts to $1.617/dkt).

221. In regard to Small Interruptible Transport (Rates 80 and 81) MDU and DEQ testify on Rate 81 issues. MDU addresses rate design changes and MDEQ addressed the need for interruptible rates.

222. Although Aberle testifies that the interruptible transport Base Rate will match the charge on their interruptible sales counterpart tariffs, this relation is missing with Rate 81. She also proposes combining the rates for positive displacement and orifice meters on Rates 80 and 81.[28] To eliminate confusion, she substitutes Base Rate for "minimum revenue contribution" on

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[27] MDU excludes any billing determinants for Rate 85.

[28] Note that MDU combines Rates 80 and 81 in certain testimony. Rate 80 is MDU's Electric Generation Interruptible transport rate. For Rate 80, MDU proposed to decrease the Base Rate for orifice meters from $1192/month to $185/month for its electric generation plants. For displacement meters the Base Rate rises to $185 from $151/month.

all transport tariffs. She bases the commodity charge price ceiling on the margin approach (sales rate less gas costs) and left unchanged the floor price of $.101/dkt. In response to discovery (MDU response to PSC-27(c) and 134(b)) MDU states no objection to raising the commodity price ceilings so long as MDU continues to have price flexibility. MDU favors a "market based" price cap.

223. Frantz's testimony relates MDU's loss of customers to rate design. Although he testifies that WBIP's rates are the primary source of MDU's load loss, he also attributes losses to MDU's rate design. He believes firm transport Rate 84 is too high and the interruptible transport rates are too low. As customers shift to interruptible transport the contribution to fixed costs is reduced and other customers' rates must increase. He believes that customers will not likely be interrupted given MDU's distribution capacity surplus and interruptible service has value only if a system has a capacity shortage. Interruptible rates should not serve as retention rates but rather should reflect the benefits conferred on the distribution system. He recommends realigning MDU's firm and interruptible transport rates, preferably by reducing Rate 84.

224. In rebuttal Aberle disagrees with DEQ's assumption that impacts will not arise when customers convert from firm sales to firm transport. She asserts that firm sales rates will increase due to the tracker. Based on an "average return on investment" criterion, it makes no sense to lower firm transport rates below that proposed in this docket. While flexibly priced rates serve a retention function she believes such rates benefit other customers.

225. Pertaining to Large Interruptible Transport (Rate 82), as with Rate 81, Aberle ties this tariff's Base Rates to those on an interruptible sales tariff (Rate 85) and proposes to substitute Base Rates for the term "minimum revenue contribution." Rate 82's $1,250 Base Rate, however, exceeds sales Rate 85's Base Rate of $1,150. She explains the basis of the ceiling and floor prices for Rate 82. The ceiling commodity charges were developed based on the margin approach (sales rate less gas costs). Based on "competitive factors" MDU lowers the floor price to $.08/dkt.

226. For Firm Transport (Rate 84) Aberle's revised transport rate reflects the decrease in the Firm General Service Rate 70 revenue requirement. The Base Rates rise to either of $185 or $1,250/month depending on the otherwise applicable sales tariff. The transport rate falls from $1.296 to $1.036/dkt. The fuel charge falls from $.037 to $.031/dkt.

227. In rebuttal Aberle asserts that Rate 84 can not be reduced below that level in her direct testimony without providing less than an average rate of return on investment.

228. For MDU's proposed Rate 92, Weather Normalization Adjustment (WNA), MDU proposes that it not be optional to firm residential and general service sales (Rates 60, 62, 70, and 72). According to Aberle, the WNA is needed due to the weather sensitivity of MDU revenues (49 percent of MDU's non-gas costs are weather dependent). Her survey revealed that over 31 utilities in 14 states and Canada have a WNA.

229. Aberle explained how the WNA operates.[29] MDU would apply the adjustment to winter months only (November through April). A customer’s net load would be computed by subtracting base load (lowest summer month use) from actual load. The net load would be stated on a heating degree day basis by dividing by that month’s actual heating degree days. MDU would then multiply the result (load/heating degree day) by the difference (variance) between normal and actual heating degree days for a billing cycle. Finally, MDU would multiply the result times the authorized tail-block margin (the commodity rate less the cost of gas).[30]

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[29] To explain the adjustment, consider two actual winter weather conditions in relation to normal (average) winter weather. One condition is colder than normal and the other hotter than normal. All else remaining the same, if actual weather is colder than normal, MDU collects too much money and the customer receives a rebate, but if actual weather is hotter than normal customers are surcharged because MDU would collect less than normal revenues.

[30] MDU’s Rate 92 includes the weather normalization

equation WA ‘ {(ACT-BL) * (NDD-ADD) * M} / ADD, where WA is weather adjustment, ACT is the actual consumption (dkt), BL is the base use (dkt), ADD and NDD are, respectively, actual and normal heating degree days, and M is the class margin.

230. Donkin lists several problems with the WNA. To Donkin the adjustment is not revenue-neutral, distorts price signals, and reduces MDU's business risk. He illustrates the lack of revenue neutrality by analyzing equal deviations about normal weather. For equal weather variations, MDU collects more revenue with warm weather than it loses with cold weather. He argues that reduced charges for cold weather and higher charges for warm weather distort price signals. As for business risk, he asserts that the adjustment reduces from 55 percent to 6 percent the percentage of MDU non-gas revenues that would be subject to risk of throughput fluctuations between rate cases. According to Donkin risk is further reduced to less than 4 percent when customer class revenues are shifted as proposed by MDU. He argues that, just as the Commission rejected Great Falls Gas's (GFG) Sales Adjustment Mechanism in Docket No. 84.4.25, MDU's WNA should be rejected, but if the Commission were to approve the adjustment, MDU's authorized rate of return on common equity should be significantly reduced.

231. In rebuttal, Aberle criticized MCC's weather normalization adjustment testimony. In regard to the absence of revenue neutrality she asserted having used 30 years of data to develop normal degree days. Aberle asserts that the adjustment is only revenue neutral on a month-to-month basis if the "use per degree day" is the same and the variance in degree days is offsetting in nature. In reference to the GFG Sales Adjustment Mechanism, she raised an argument involving customer conservation efforts. Whereas the Sales Adjustment Mechanism applies to total revenues, she emphasizes that the GFG adjustment only adjusts actual heat use. Her example illustrates why the adjustment has

no customer conservation effect and her conclusion is that the adjustment is revenue neutral.

Commission Rate Design Decisions

232. The Commission finds no merit in MDU’s rate design proposal to rebalances rates with a consequent $1.5 million revenue requirement shift to the residential class. Rebalancing is not timely, in part due to the absence of a thorough cost of service debate in this docket (gas costs were not fully debated). As MCC testified, and MDU affirmed, this docket is about non-gas costs and revenues. Therefore, the Commission finds merit in MCC’s focus on non-gas costs and its objection to rebalancing. MCC’s argument is persuasive. As a constructive comment, the Commission suggests that an expedient means to thoroughly explore gas and non-gas costs may be to include class cost of service and rate design as an issue in association with an MDU tracker (but not until sometime in 1997). The Commission simply seeks a solid link between all costs, including tracker related gas costs, and the subsequent rate designs that are candidates for rebalancing. However, the Commission finds that approval of a number of MDU rate design proposals should serve to mitigate concerns MDU may have in regard to rebalancing.

233. For MDU’s Residential Rate 60 the Commission finds merit in spreading the authorized revenue increase of about $1,008,687 to base and commodity rates. By spreading this entire revenue increase to the residential class other classes will be spared the responsibility of any increased revenue requirement in this docket. The Commission denies MDU’s declining-block rate design proposal. The merit of such a rate design must be tied to

a more thorough cost analysis than that which emerged in this docket. In a future (and complete) MDU cost of service study, the Commission will reconsider the merits of a declining-block rate structure.

234. Since the declining-block rate design is denied, the existing two-part tariff on Rate 60 shall be used to recover the increased revenue requirement. The Commission finds merit in increasing the residential Base Rates by a percent increase that exceeds the overall increase for this class. That is, the Commission rejects MCC’s proposal to spread the revenue increase to the residential class on an equal percent basis to each rate element.

235. The Commission’s reason for increasing the Base Rates $.50/month are twofold. Clearly customer costs exceed this amount. Spreading more of the increase to base rates will mitigate the level to which the commodity price would otherwise have to rise. Even though the Commission’s decision to increase Base Rates by $.50/month is inconsistent with MCC’s proposal, the small metered customer’s Base Rate will not exceed the $5.13 level in Donkin’s testimony. Therefore, a $5.00 Base Rate should cause MCC no alarm. The Commission’s reason to not spread the entire increase to the Base Rate or, for example, to the first block of MDU’s declining block rate structure proposal, is so that customers have some choice about avoiding the increased revenue requirement. If the entire amount is put on Base Rates there is essentially nothing a customer can do, aside from ceasing service, to avoid the increase. By spreading some of the increase to the commodity rate customers can make choices that allow for the avoidance of such costs. When MDU has filed a

thorough cost of service study and the true costs of all services, not just residential, are evident, the Commission will entertain a declining-block rate design proposal.

236. As for implementation, the Commission finds that MDU must set residential Rate 60 Base Rates at $5.00 and $10.50 respectively for the small and large metered customers on each of Rates 60 and its seasonal counterpart Rate 62. MDU is to recover the balance of the revenue increase from the flat-rated commodity price. The Commission expects the current (April 3, 1996) commodity price, prior to any tracker adjustment, will rise by about $.11/dkt to recover the remaining revenue increase of about $659,000.

237. For MDU’s General Service Rate 70 the Commission disapproves rate changes. Until MDU makes a thorough cost of service filing, that includes gas and non-gas costs, this tariff’s rate design will remain. Tracker adjustments to this and other tariffs will continue.

238. For MDU’s Small Interruptible Rate 71 the Commission approves MDU’s proposed flexible pricing and the elimination of the 6,000 threshold to qualify for this tariff’s rates. Other proposed changes are disapproved. As MDU only has one Rate 71 customer, MDU has the opportunity to attract new customers and increase its interruptible sales loads in Montana. Such flexibility carries with it a challenge for MDU to not discount prices unnecessarily.

239. For MDU’s Large Interruptible Rate 85 the Commission denies MDU’s requested rate changes for this class. The Commission is puzzled as to how MDU can assert to have designed this tariff’s commodity rate on a “residual” basis to achieve

this class’s revenue requirement given there are no Rate 85 customers. Absent a revenue allocation, residual revenue requirements do not exist. Even though MDU has no Rate 85 customers the Commission finds MDU’s testimony to change rates to lack substance. MDU’s increased Base Rate proposal should probably be unbundled to reflect different meter costs.

240. For MDU’s proposed WNA (Rate 92) the Commission denies MDU’s request. MCC’s reasons for denying the adjustment are persuasive. The Commission also believes that weather related risks are expected in the utility industry.

241. The Commission finds that the changes in this docket will serve to enable MDU to be more competitive. The increased revenue requirement per MDU’s proposal will fall entirely on the residential class (Rates 60 and 62), thereby mitigating increases to other classes. MDU will for the first time be allowed to flexibly price interruptible sales on a tariff (Rate 71) that now has only one customer, thus, there is only room for demand growth on Rate 71.

242. MDU has four transportation rates. For Electric Generation Interruptible Transport (Rate 80), MDU’s recommended changes to this tariff were eclipsed by seemingly more important issues. After comparing the availability language on Rate 80 to that on Rate 82, and after comparing the cost of metering Rate 80 and Rate 82 customers, the Commission denies MDU’s request to lower Rate 80's Base Rates. MDU’s Rate 80 serves MDU’s electric generators. Since MDU reports meter costs for these electric generators that are identical to those large metered Rate 82 customers, MDU’s request to lower Rate 80's Base Rates appears to be inconsistent with the cost of service.

243. As for any competitive impacts of not approving MDU’s request to rebalance Rate 80, the Commission makes two observations. First, it is unlikely MDU’s expansion of its electric generation facilities is contingent on the level of Base Rates in this docket. Second, MDU’s proposal to lower the Base Rate for its affiliated electric operation below MDU’s cost of service would be discriminatory. Therefore, rate rebalancing of this tariff is highly questionable at this time. MDU’s next cost of service and rate design filing should disassociate Rate 80 and 81 for cost of service and rate design purposes.

244. For MDU’s Small and Large Interruptible Transport (Rates 81 and 82), the Commission denies rebalancing changes on these tariffs. The Commission would add that the relative level of commodity rates on these and Rate 84 remains a concern. Tipton asserts interruptible transport rates are too high. Frantz (DEQ) asserts they may be too low. In the absence of an analysis of the true costs of service in this docket, neither witness’s testimony is persuasive.

245. MDU’s agreement to raise the ceiling prices on these flexibly priced rates, so long as any “market price” ceiling covers the cost of service, casts a shadow of doubt as to whether the current and lower ceilings cover the cost of service. In other words, if MDU is concerned that market-price based ceilings, that exceed the current ceilings, may not cover the marginal cost, then the current lower ceiling prices may not cover the cost of service (see, MDU’s Response to PSC-134). DEQ’s concern that these ceiling prices may be too low and the latter concern raised by MDU’s condition on market-based pricing

give the Commission pause in terms of raising or lowering either of Rate 81 or Rate 82 tariffed prices.

246. In regard to MDU's Firm Transport (Rate 84), because of the Rate 84 relation to the interconnect issue (reserved), the Commission can only decide the rate issue, subject to a later decision involving the interconnect. As initially filed by MDU Rate 84 over charged customers. Yet, MDU expressed concern over sub-average rates of return if Rate 84 prices were further lowered.

247. Although part of a larger issue involving the absence of open access (see below) the Commission finds MDU's continual errors with Rate 84 to be a problem. Earlier Rate 84 prices were exaggerated by virtue of MDU's including unavoidable and unrelated WBIP charges. Although those charges were later removed, Rate 84 remained excessive as the Commission noted in Docket No. 88.8.23. That curiosity endured until DEQ illuminated the double counting of base rates. Even though this order will eliminate MDU's double collection of Base Rates, Rate 84 is not yet clearly cost based. The Commission expects Rate 84 will receive serious analysis in any subsequent and thorough cost of service filing.

248. The Commission has two choices to eliminate MDU's double collection of Base Rates on Rate 84. Of the two, the Commission favors MDU's proposal to eliminate the separate collection of Base Rates. If cost of service were not a concern, the Commission would otherwise favor maintaining separate Base Rates with a concomitant reduction in the Rate 84 commodity price (DEQ's proposal). However, cost of service is a concern and the parties only supplied accounting cost or "margin" based arguments

for Rate 84. The DEQ's relative price concern involving interruptible transportation rates, remains unresolved. In eliminating the double collection of Base Rates the effective Rate 84 price will fall below MDU's initial expectation. MDU now has an opportunity to attract new and firm loads on a tariff that has been exaggerated with unnecessary cost allocations.

249. The above transport tariff approvals, and disapprovals, are necessary so that MDU can more effectively compete. These decisions should also serve to further mitigate the appearance of discrimination that continues to plague MDU's pricing proposals. The Commission can not in good conscience approve further price reductions on Rates 80 and 84 without much better cost information. In situations where discrimination can surface, prices simply need a better cost basis. Ironically, MDU's slowness in moving to set Rate 84 at cost based levels, since initially approved, may explain why MDU has no Rate 84 customers. Exaggerated prices, whether intentional or accidental, will discourage competition and the demand for Rate 84's service.

<u>Standby Service (Additional Issue)</u>

250. During prehearing procedures the Commission identified two additional issues in this docket. The first involved MDU's proposed standby service tariff language and an aspect of it related to an MDU affiliate.

251. On this issue MDU had proposed a tariff revision that permits MDU to automatically shut off an interruptible standby service gas supply. The revision provided that "[i]f Company-approved equipment and fuel for standby service is not installed and maintained, the Company, in its discretion, may install

automatic shut-off equipment... ." No MDU testimony accompanied this tariff revision.

252. MSU-B witness, Richard Hedman, in prefiled testimony, indicated that an MDU affiliate, Prairie Lands Energy Marketing (PLEM), proposed to furnish MSU-B with a propane standby system. To Hedman the system would be financed by MSU-B with cost savings associated with MSU-B changing from general gas service to interruptible gas service. He added that PLEM will benefit from the cost savings.

253. The PSC's additional issue notice stated the issues as follows:

> a. whether the amendments are necessary, given that MDU tariffs already allow for penalties;
>
> b. whether the proposed amendments inclusion of required "MDU-approval" for equipment and fuel is anticompetitive when a major supplier of the required type of equipment and fuel is an affiliate of MDU (Prairie Lands Energy Marketing); and
>
> c. whether firm service as opposed to installing standby equipment and fuel would better minimize societal costs.

254. The only party to testify on this additional issue was MDU. MDU witness, Donald F. Klempel, asserted that MDU made the automatic shut-off equipment proposal as the current tariff provides inadequate interruptible service.[31] To Klempel, although MDU allocates the cost of a failure to interrupt to the customer and already has the ability to shut-off a customer, the process

[31] Aberle's rebuttal states that MDU's tariffs contain penalties and charges for occasions when a customer refuses to interrupt. These provision were designed to recover any costs WBIP assessed MDU that were caused by the customer's actions.

used is ineffective and automatic shut-off equipment is needed to stop the flow of interruptible gas to customers who rely on gas marketers. Klempel asserted that, whereas customers may continue interruptible service without a "standby source of supply," the provision allows MDU to install automatic shut-off equipment at the customer's expense. To Klempel on-site visits will then be avoided.

255. Klempel's position is that the "anti-competitive" concerns are unfounded, as there is a highly competitive market for standby equipment and fuel. Klempel comments that MDU's tariff will not specify any particular standby fuel or equipment. MDU's legal counsel apparently offers insertion of any proper anti-discrimination provisions in the tariff.

256. In response to the question of whether firm service was of a lesser societal cost then standby given the added fuel and equipment cost associated with standby, Klempel asserts societal costs may not be impacted if customers make economically rational decisions.

257. The Commission approves MDU's proposed tariff revision allowing the automatic shut off of interruptible customers, but with two conditions. First, the charges (for company installed equipment) must be tariffed with explicit rates or with reference to market rates, such as the cost of a required telephone line, or a combination of the two. This requirement stems in part from the fact that MDU must have no less uncertainty with metering costs than it does with shut off equipment. Second, MDU is not to allow marketers or pipelines (e.g., WBIP) to use the shut off equipment to activate any rights that they may have to interrupt loads, if those rights are independent of MDU's, although MDU may

use its shut off equipment for that purpose if a tariffed rate exists for that use. The Commission intends to audit MDU's compliance with this finding in subsequent cost of service and rate design dockets.

Interconnect with MPC (Additional Issue)

258. Prefiled testimony from DEQ prompted a second additional issue (which later became a reserved issue). The issue involves an MDU interconnect with Montana Power Company's gas system at or near Billings, Montana. As indicated in the introduction to this Order, this issue has been designated a reserved issue and is governed by its own procedural schedule. The Commission will issue a decision on it after having had the opportunity to review the record and arguments. Of the possible decisions several could affect rates established by this Order. Until such time the rates (e.g., Rate 84) established by this Order are final.

Future Cost of Service and Rate Design Filing -- Unbundling

259. Full unbundling of natural gas services is a current gas service issue and one that should also be explored in relation to MDU's gas service. Issues involving open access are not entirely new to MDU or the Commission. In Docket No. 88.8.23 the Commission expressed an interest in allowing residential customers to aggregate to obtain better economic opportunities than might then have been otherwise available through MDU (the Commission is unaware of any MDU response to that interest).

260. Therefore, in its next cost of service and rate design filing MDU must file testimony on complete unbundling and open

access for all customers, including residential customers, and the reasons why such should or should not be implemented as a part of MDU's natural gas services.[32] Except for good cause, the Commission will not entertain future MDU cost of service and rate design filings, including any rebalancing proposal, without such testimony. In regard to unbundling the Commission's interest includes aspects such as cost-based open access for all customers individually and in aggregate, elimination of tariff conditions that obstruct customer options (e.g., the constraint on who can take Rate 84 service), and allowance for residential customers, individually or in aggregate, to take firm transportation service over MDU's distribution system.

CONCLUSIONS OF LAW

1. All findings of fact, analyses, and decisions which can properly be considered conclusions of law and which should be considered as such to preserve the integrity of this Order are incorporated herein as conclusions of law.

2. MDU is a public utility pursuant to provisions of Title 69, MCA, including at sec. 69-3-101, MCA. MDU's application for a change in rates is a matter properly under the jurisdiction of the PSC pursuant to provisions of Title 69, MCA, including at Title 69, ch. 3, MCA.

3. MDU's application, resulting PSC notices, public participation and interventions, hearings, arguments, actions, and decisions are complete (except those reserved), proper in

[32] The PSC has directed Montana Power Company in a similar fashion. See, Docket No. 92.2.22, Order No. 5898, p. 3 (February 20, 1996).

form, and have been conducted according to the laws of Montana, including as may be provided in Title 69, MCA (public utilities and carriers), ARM Title 38, chs. 2 (PSC procedural rules) and 5 (public utilities), and Title 2, ch. 4, MCA (MAPA).

4. In accordance with Title 69, MCA, including at secs. 69-3-201 and 69-3-330, MCA, the rates approved in this Order are just and reasonable and not discriminatory.

ORDER

1. All conclusions of law which can properly be considered an order and which should be considered as such to preserve the integrity of this Order are incorporated herein as orders.

2. All pending motions, objections, and arguments which have not been specifically ruled on in this Order or otherwise properly reserved for future consideration are denied to the extent that denial is consistent with this Order.

3. Docket No. D95.10.145's, Order No. 5870a, the PSC’s October 27, 1995, Interim Order in MDU’s fall, 1995, gas cost tracking adjustment procedure, is adopted as the Final Order governing that matter, provisions in it which pertain only to its interim nature to be disregarded.

4. To the extent that it may be necessary for purposes of clarity, the PSC’s decisions on the revenue requirement and cost of service and rate design aspects of this proceeding, as set forth in the findings of fact, analyses, and decisions above, are incorporated herein as orders.

5. Reserved issue decisions remain pending. Of the possible decisions on those issues, one or more could affect the terms of this Order. If that should occur the PSC will attempt

implementation in a way that results in the least disruption to rates, as fixed by this Order, as is possible.

6. In its next filing which includes cost of service and rate design for gas service in its Montana territory, MDU must include testimony on complete unbundling and open access for all customers and testimony on the reasons why such should or should not be implemented as a part of MDU's gas services.

7. MDU is ordered to comply with all PSC directives included in this Order and all compliance provisions of applicable statutes and rules which may govern proper implementation of this Order and rates established by it.

Done and dated this 11th day of April, 1996, by a vote of 5-0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

NANCY MCCAFFREE, Chair

DAVE FISHER, Vice Chair

BOB ANDERSON, Commissioner

DANNY OBERG, Commissioner
(concurring opinion - attached)

BOB ROWE, Commissioner
(dissenting in part - attached)

ATTEST:

Kathlene M. Anderson
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.

Concurring Opinion
Commissioner Danny Oberg
Order No. 5865b
Docket D95.7.90

I concur in large part with the findings contained in the Majority Opinion of this case. The results of this case fulfill the Commission's statutory obligation to balance the interests of ratepayers and the utility and result in rates that are just and reasonable. It meets all of the criteria established over the years in case law and precedent to assure adequate service and profits commiserate with the investors risk.

In some respects this decision contains important policy considerations that warrant a more complete review than is present in the decision. This opinion is written to amplify the explanations contained in the opinion and does not represent a departure from the conclusions.

Introduction

Montana-Dakota has called this case a watershed case. The Commission was challenged to not view the case in terms of business as usual, but rather as an opportunity to more closely align rates with actual costs of providing service and to permit the utility to price correctly in view of competitive pressures. I believe the Commission decision has responded to the challenge as appropriate and consistent with the facts. The interests of the ratepayer and the utility have been well served.

Montana Dakota's natural gas utility presents the regulator with some unique challenges. Although it serves a large portion of eastern Montana and is a major utility when measured by either customers or revenues, it is an atypical utility for rate making. Since it is solely a distribution company and has no investment in either transmission or gas supply it has a relatively small rate base. As such adjustments that would be lost in the rounding process for other utilities can have a profound impact on Montana-Dakota's ability to earn its authorized rate of return. Changes in rate of return of a full point only produce $137,000 in revenue. Conversely, denial of only $137,000 in expenses will result in a full drop of 1 point of the utilities ability to earn its authorized rate of return. Hence, the regulator must exercise extreme caution in consideration of the elements of a rate case if it is truly committed to giving the utility a real opportunity to earn its authorized rate of return.

The relationship between Montana-Dakota and the Commission has been tortuous. From the late 1970's and continuing through the 1980's the relationship between the two was largely adversarial in nature. I believe the Commission had just cause to adopt an aggressive regulatory stance with Montana- Dakota. Rates were rising rapidly and there was consistent evidence that Montana-Dakota was not fulfilling its responsibilities as a public utility to provide the customer with reasonable priced utility services. Its dependence on a sister company with very high cost gas relative to market prices was viewed as antithetical to the public interest. Montana Dakota appeared reluctant to support the interests of its customers in federal forums when it might affect its sister company or use what freedom it was given to acquire gas supply from other sources. Rate cases were almost pancaked with this Commission and Montana- Dakota rates became significantly higher than other Montana utilities. Consumers were angry and often flocked to public hearings. The public interest required that the Commission adopt a rate minimization strategy.

Those days appear to be over. Present rates are the lowest since 1981. New Montana-Dakota management has diversified the companies supply portfolio, adopted a rate stability policy and appears to be acting consistent with the public interest. Such a condition does not mean the Commission can ignore its regulatory responsibilities, but it definitely affords the regulator an opportunity to pursue other important regulatory goals such as correct pricing and a better realignment of costs and rates.

The Commission process for granting a revenue increase or decrease is based upon a thorough examination of all the underlying costs presented by the utility and any exceptions noted in the record by intervenors (the Montana Consumer Counsel in this case) or through cross examination from the Commission and its staff. It is the results of these issue by issue examinations of contested issues that a final revenue requirement is produced and not from some predetermined level of acceptable earnings.

The decisions on these adjustments must conform to law, the evidentiary record, and Commission and judicial precedent. They must stand alone on the merits presented. In addition, I believe these adjustments must be viewed as part of a broader picture and be correct in terms of current public policy, the political and regulatory environment in which the case is filed and also be compatible with the regulators concept of long term goals for the utility under consideration. To not recognize this broader context would be naive, ignore the Commission's obligation to properly balance conflicting economic interests and ill serve the public interest. In my opinion, adjustments must be technically sound and also consistent with the more global concerns of the regulator as he oversees the utility.

Both customers and utilities are most concerned with the bottom line of any case. Ratepayers tend to be more concerned with the rates they will pay and utilities with the profits they will generate. While the revenue request granted is about one half of the applicant's request I believe the Commission has fairly decided the case. Montana-Dakota has been given a real opportunity to earn profits at a level consistent with investor expectations, while not excessively burdening the ratepayer with costs beyond that which has been incurred with providing service.

I would like to more fully address certain revenue requirement issues as well as the Commission's decision on rate design issues.

Revenue Requirement Issues

Post Test Year Plant Additions

The most contentious of the revenue requirement issues concerned Montana-Dakota′s proposal to include certain ongoing business expenses as post test year plant additions. This Commission has consistently developed a method of regulation based upon the historical test year concept. A "snapshot" look taken of a utility during a particular time period is used as the basis for setting rates. Over time the Commission has found that this method is the best proxy for setting rates prospectively. It is neither speculative in nature nor unduly reliant on judgement as current and future test year cases tend to be.

The Commission, as a matter of public policy, has chosen to rarely depart from this standard. Yet, the Commission′s rules do allow for inclusion of such costs under certain conditions. The majority opinion in this case outlines those requirements.

As the Commission has noted, the applicant presented this adjustment consistent with the criteria previously outlined in the Commission′s own rules and past orders. The rules and past rulings must be considered permissive in nature. As such, the Commission found that it *could* grant the applicant the relief requested. The question of whether the Commission *should* grant the rate basing or reject it as a weakening of the historical test year was debated at great length. It is my opinion that the Commission′s rules do not mandate post test year plant addition recovery, but are merely permissive even when the utility filing conforms to Commission rules.

In my fourteen years as a regulator I consider the depth of the debate and Commission consideration on this issue was unprecedented. The Commission did not depart from its past policy without careful consideration of all of the relevant concerns. I think it is important to note that my belief is that the Commission has not enunciated a reversal of its historic reliance on the historic test year. Rather, it has said that under certain conditions the Commission is willing to go beyond the test year.

First, the applicant must prove that such an adjustment is consistent with the criteria established in the Commission rules and meet that test as a first hurdle. Secondly, after that test is met, the correctness of such an adjustment must pass scrutiny on broader level. There are public interest criteria that must be met before the Commission will depart from the historic test year. In the absence of clear balancing considerations, I believe the Commission should not depart from the historic test year.

I believe the Commission made the correct assessment in this case. It has recognized that Montana-Dakota is an atypical utility which requires special consideration to allow the utility to have a real opportunity to earn its authorized rate of return. It also factored in a number of other considerations in its debate that eventually led to the acceptance of post year plant additions into rate base. Some of these factors include:

1. Montana-Dakota's infrequent general rate filings.
2. The balancing that was needed to offset the addition of certain plant subtractions from rate base due to office closures.
3. Timing problems associated with case. Due to a prior stipulated agreement the timing of this case was predetermined to result in an April rate change.
4. The fact that most of the plant additions under debate had been in service for at least three months and some for as long as 15 months when the rates in this case will be effect.
5. The magnitude of earnings erosion that would take place if the additions were denied rate treatment.
6. New management that has taken decisive steps to shield ratepayers from high purchased gas costs and a corporate rate strategy to minimize costs and stabilize rates stable through infrequent filings .

In fact, during debate I argued a dozen points why the addition of post test year plant additions in this case was good public policy and consistent with the intent of the Commission's obligation to balance the interests of the utility and the ratepayer.
I believe the Commission's decision reflects that the utility met its burden of proof on both tests I have outlined. The addition of post test year plant additions complies with the rules of the Commission and is further justified by the unique factors of Montana-Dakota. In fact, I am of the opinion that to not allow the inclusion of the post test year plant additions would have denied the utility an opportunity to earn its authorized rate of return. The latter test and conclusion may not always be met by other utility filings.

The utility industry, in general, should be cautious in its interpretation of this ruling. By no means, should it be read as an indication that the Commission intends to forsake its reliance on the historic test year. Except when the record fully supports Commission precedent and rules and further meets broader public policy tests I fully expect such post test year plant additions to be denied.

Cost of Service / Rate Design Issues

The Commission has rejected the applicants proposal to shift part of the imbedded revenue requirement from commercial and industrial customers to residential customers. The Commission did note it is not unsympathetic to competitive pressures, but found that it would be improper to shift revenue responsibility without a complete examination of underlying costs. While the Commission did not grant Montana-Dakota's rebalancing proposal it recognized that Montana-Dakota is facing real revenue loss from competitive providers and fuels and did not wish to further erode Montana-Dakota's competitive position in the marketplace. In the absence of more definitive costing information, the order places the additional revenue requirement responsibility on the residential customer - the most inelastic of Montana-Dakota's customer classes. Preventing the loss of either sales or transportation revenues is in the best interest of residential customers to avoid future increases for residential customers who would be held responsible for more of the utilities fixed costs. The Commission may not have gone the full length as requested by Montana-Dakota, but it went as far as it could consistent with the evidentiary record.

I support that decision fully. This Commission has long set rates based on costs established by a thorough examination of cost of service studies. The Commission did not have sufficient data before it to fully examine all of Montana-Dakota's costs to establish sound rates. As the order notes the anecdotal evidence presented by Montana-Dakota of lost load could be due to other factors (like WIBPC rates) and not Montana-Dakota's rate design. In the absence of a full cost of service study the Commission is unable to make that determination. This Commissioner also believes that Montana-Dakota should consider previous Commission precedent and explore customer specific retention tariffs to stem the flow of revenues from migration off the utility system. I would be willing to revisit these issues when, and if, Montana-Dakota files a complete gas and non gas cost of service study.

While supporting Montana-Dakota pricing policy conceptually and conditionally for the short term, the Commission chose to give direction to file testimony in future rate cases on further unbundling and open access for residential customers. The history of the natural gas business reflects an ongoing transition from a closed monopoly structure to a progressive opening up of the system to greater customer choice. Beginning with the Natural Gas Policy Act of 1979 utilities were given new supply opportunities as the price of gas at the wellhead was deregulated. Then, through a series of federal orders issued by the Federal Energy Regulatory Energy Commission, the interstate pipeline business was opened up to full access to competing suppliers of natural gas. Both utilities and large customers were given greater freedom to pursue cheaper fuel sources. Within the utility and regulatory world there is growing discussion that the time has arrived to bring this transition to its obvious completion and allow even residential customers (either individually or in the aggregate) to pursue their own supply and transport it through the utility system. The Commission recently participated in a nationwide satellite presentation by the American Gas Association on this very point.

Over the long term, I have reason to believe that residential customers should have the choice to leave the system much as commercial and industrial customers presently are able to. In this order, the Commission has served notice that it wants to give a future Commission the opportunity to consider this option. Montana-Dakota is given its full opportunity to lead this discussion by filing the requested testimony. The Commission has not mandated further opening of the Montana-Dakota's system, but merely said Montana-Dakota must present thorough testimony on the appropriateness of such a policy. The time has arrived for the debate to come to Montana.

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Danny Oberg
Commissioner

DISSENT OF COMMISSIONER ROWE

Docket 95.7.90

I dissent from two decisions in this matter. I would not include general post-test year plant additions in rate base. I would not grant a twelve percent return on equity.

A. Post-test year adjustments.

Montana uses an historical test year. The reasons for doing so are compelling. Moving away from an historical test year requires much greater ability to scrutinize budgeted figures. In contrast, historical figures are known with certainty. The petitioning utility presumably knows the adjustments which will favor its case. It is much more difficult for opposing parties to determine what if any adjustments might be adverse to the applicant and favor the customers. Historical test years are particularly appropriate for smaller states with limited resources.

Post-test year adjustments are usually granted only under exceptional circumstances. I agree that expenses related to office closings are extraordinary in nature, and should be granted. However, a blanket inclusion of all known and measurable post-test year changes is unprecedented, and potentially represents a substantial deviation from an historical test year. Such a change should be made only after explicitly considering the policy issue, and giving all interested parties an opportunity to comment on the merits of such a significant policy change. Although the majority carefully reviewed the record and concluded that the record in this case supported granting the adjustment, it did not benefit from a full discussion of the policy considerations which would support or oppose such a change.

When post-test year adjustments are allowed they must be known and measurable, and positive and negative adjustments must be correctly matched. The majority considered whether the dollar amount of the proposed adjustments were known and measurable with reasonable accuracy, and whether other causally-related changes in expenses or revenues were matched with the adjustments. The majority concluded the adjustments were known and measurable and that the record provided a basis for making appropriate matches. The Montana Consumer Counsel filed testimony challenging the adjustments on these bases. At the very least, the majority appears to have markedly lowered the level of precision required in matching positive and negative adjustments. Presumably because MCC believed the adjustments did not pass these two tests, its testimony and briefs did not squarely address the policy issue on which the majority decision appears to rest.

MDU argued and the majority agreed that the rate base should include plant in service as close as possible to the time rates will be in effect. For utilities which do not want to use an historical test year, the Commission has adopted optional filing requirements which explicitly allow rate base to be determined using year-end figures. The optional rules were adopted to meet specific industry concerns, the same concerns raised by MDU in this case. They were adopted after extensive study, comment, and consideration by the Commission. Typically, a utility will elect to file under the optional or traditional rules based on a determination of which approach will be most beneficial to its case. MDU elected to file under the traditional rules, and should receive a rate base decision consistent with past practice using an historical test year.

B. Rate of Return.

The majority approved a return on common equity stock of 12 percent. This is extraordinarily generous. An 11.25 percent return on equity would be appropriate, justified by the record, and consistent with the market. I would accept an upward adjustment to as much as 11.5 percent to reflect possible greater riskiness due to MDU's smaller revenue base compared to the sample utility group. However, I do not believe MDU is facing a risk of bypass greater than that faced by other natural gas local distribution companies, and therefore do not believe an additional increase should be granted on that basis.

C. Conclusion.

I agree that MDU presented a strong record in this case. However, despite attempts to confine the decision to this record, I believe the majority's decisions may return to haunt other Montana utility customers in pending and future cases.

RESPECTFULLY SUBMITTED this 17th day of April, 1996.

BOB ROWE

Commissioner