

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application**

Case No. PU-399-02-183

**STAFF PROPOSED
FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER**

November 15, 2002

Appearances

Commissioners: Susan E. Wefald, Leo M. Reinbold, Anthony T. Clark.

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Allen C. Hoberg, Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, presiding Administrative Law Judge.

Preliminary Statement

On April 12, 2002, the North Dakota Public Service Commission received an application from Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) to increase its natural gas rates in North Dakota by \$2,844,132 annually. MDU's application is based on a calendar 2003 projected test year.

In its application and supporting testimony and exhibits, MDU requests an increase in its rates for gas distribution service of \$2,844,132, or approximately 4.1 percent based on a forecast 2003 test year. The primary reasons for MDU's application are increased operation and maintenance costs, depreciation, and taxes other than income, and a higher required rate of return. MDU's requested return on rate base is 11.044 percent, inclusive of a return of 13.25 percent on the 51.687 percent of total capital that MDU asserted to be represented by common equity.

Staff proposes that MDU's test year 2003 rates be decreased by \$1,402,000. This reduction is based on a rate of return on rate base of 7.980 percent, inclusive of a 10.5 percent return on 44.55 percent equity proportion of total capital and a much lower cost of debt.

MDU also requested a significant restructuring of its rates, including a separation of gas distribution from gas supply charges, elimination of declining block commodity charges and dramatic increases in customer charges. Additionally, MDU has proposed that all increases be flowed into the firm residential and commercial rate schedules, that no change in rate levels be applied to the Air Force and large interruptible schedules, and that the small interruptible class should receive a rate reduction.

On April 24, 2002, the Commission suspended MDU's rates filed with its Natural Gas Rate Increase Application. On June 5, 2002, the Commission issued its Notice of Hearing Notice of Public Input Sessions, and Notice of Intervention Deadline. Public input sessions were held via video teleconference on July 15, 2002, in Bismarck, Dickinson, Williston, Minot, Devils Lake, and Jamestown. The technical hearing was held in the Commission Hearing Room at the State Capitol in Bismarck, North Dakota on October 7-8, 2002.

The Notice of Hearing specified the issues to be considered at the technical hearing, which are:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?
3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?
4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?
5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?
6. Other relevant information or proposals concerning the proceeding.

The Notice of Hearing provided that any person wishing to intervene as a party in the proceeding must file a petition for intervention by September 9, 2002. No one petitioned to intervene as a party in the proceeding.

The Commission, having reviewed the evidence in the record makes the following:

Findings of Fact

1. MDU is an investor owned utility company operating as a division of MDU Resources Group, Inc. providing natural gas distribution service in North Dakota.
2. The parties do not dispute the:
 - 2003 test year for rate determination.
 - Jurisdictional cost of service study.
 - 2003 test year for rate base (except accumulated reserve for depreciation)
 - Cost of preferred equity.
 - Test year revenues.
3. The parties dispute the following issues:
 - Cost of capital
 - Depreciation
 - Bonuses and labor expenses
 - Supplemental Income Security Plan
 - Rate case expense
 - General inflation adjustment for expenses
 - Other unadjusted operation and maintenance expenses
 - Allocation of cost to customer classes
 - Rate design
 - Distribution Delivery Stabilization Mechanism

Test Year Rate Base

4. MDU and Staff are in agreement on the amount of rate base for the 2003 test year with the exception of accumulated reserve for depreciation. The staff adjustment for this issue is affected by a staff adjustment to depreciation expense of \$2,172,000. This adjustment to depreciation expense increases rate base by \$1,086 for the 2003 test year.

5. The Commission finds the following 2003 test year rate base:

Average Rate Base	(Thousands) (Thousands)	
<u>Description</u>	2003 Company Test Year	Staff Adjustments
Plant in Service	\$72,793	
Accum. Res. for Depreciation	\$49,356	\$1,086
Avg. Net Plant in Service	\$23,437	
Constr. Work in Progress	\$0	
Materials & Supplies	\$439	
Fuel Stocks	\$22	
Prepayments	\$84	
Other	\$44	
Accum. Def. Income Taxes	(\$3,842)	
Accum. Invest. Tax Credits	(\$231)	
Customer Advances	(\$272)	
Average Rate Base	\$19,681	\$20,767

Cost of Capital

6. MDU proposes a post-tax rate of return of 11.044 percent, which includes a 13.25 percent return on the 51.687 percent of its capital represented by common equity. Staff has recommended a return of 7.98 percent, including a 10.5 percent return on 44.55 percent of MDU's capital that it finds to be represented by common equity. Using MDU's 39.61 percent federal and state income tax rate, the pre-tax rates of return can be calculated as follows:

MDU:

	Cost	Proportion	Post-Tax	Tax	Pre-tax
Long-term Debt	9.180%	43.039%	3.951%		3.951%
Preferred Stock	4.662%	5.274%	0.334%	0.090%	0.244%
Common Equity	13.250%	51.687%	9.562%	2.713%	6.849%
Total		100.000%	13.847%		11.044%

Staff:

	Cost	Proportion	Post-Tax	Tax	Pre-tax
Long-term Debt	6.167%	47.92%	2.96%		2.96%
Short-term Debt	4.542%	2.78%	0.13%		0.13%
Preferred Stock	4.630%	4.75%	0.31%	.09%	0.22%
Common Equity	10.50%	44.55%	6.53%	1.85%	4.68%
Total		100.00%	9.93%		7.98%

7. The difference between the two pre-tax rates of return is 3.917 percent. When applied to MDU's projected test year rate base of \$19,681,000, this difference amounts to \$771,000. When applied to the Staff's recommended rate base of \$20,768,000, the difference comes to \$813,000.

8. As demonstrated in the foregoing tables, the Staff differs from MDU with respect to all of the components that make up the rate of return: the capital structure, the cost of debt, and the cost of equity.

Capital Structure

9. Capital structure refers to the makeup of MDU's capital, that is, the mix of debt, preferred stock and equity. Two factors account for the disagreement between Staff and MDU. The first is Staff's inclusion of short-term debt, and the second is Staff's use of year-end 2001 capital structure instead of MDU's projection of its capital structure into 2003.

10. In its initial filing, MDU excluded all short-term debt from its proposed capital structure. Staff's rate of return witness, Charles W. King, testified that the makeup of the capital structure used to develop a rate of return should reflect the nature of the rate base to which that return is applied. If the rate base consists solely of capital investments in plant and equipment financed by long-term debt, preferred stock and equity, then it might be appropriate to exclude short-term debt. But MDU's rate base also includes materials and supplies inventories, fuel stocks, and prepayments, which are short term commitments that will be financed in part with short-term debt. For this reason, he included short-term debt in the capital structure.

11. On rebuttal, MDU witness Craig Keller argued that the items to which King referred, materials and supplies, prepayments and fuel stocks remain relatively constant, not changing materially from one month to another. While classified as short-term assets, they support long-lived assets such as plant, property, equipment and related items. They are therefore financed by long-term debt, according to Keller.

12. At the hearing, King responded to Keller by producing Exhibit 13, which shows the month-to-month amounts of each of the major elements of working capital during the 13 months from December 2000 through December 2001. That exhibit

demonstrates that net working capital varied from negative \$53,000 in January to positive \$306,000 in July. King concluded that these widely varying amounts would not have been financed with long-term debt.

13. The second difference between the Staff's and MDU's capital structure relates to the use of historical vs. forecast data. King drew the amounts of debt, preferred stock and common equity from Company supplied data for calendar year 2001. He calculated average long-term debt from Exhibit 2, Statement A, page 2; short-term debt from a response to a data request (Exhibit 15, CWK-1); and preferred stock and common equity from Exhibit 2, Statements A and F, page 1.

14. MDU's capital structure was presented on Statement F, page 3 as its projected 2003 capital mix. King objected to this use of a projection on the grounds that it is effectively a creation of MDU that has no basis in any verifiable financial statements.

15. On rebuttal, MDU witness Keller argued that NDCC § 49-05-04.1 permits MDU to use a forecast test year and that Staff witness, Michael J. Majoros, had accepted the 2003 test year as the basis for revenue requirements. Keller argued that failure to use a forecast capital structure would result in a "mismatch" with the rest of the revenue requirement calculation. Keller argued that MDU possesses a financial forecasting system that uses known debt scheduling and projects equity by forecasting earnings and deducting dividends.

16. In his oral direct testimony, King pointed out that MDU had used an historical capital structure in its recent electric case. He argued that the purpose of the future test year is to capture exogenous changes that can be objectively determined, such as inflation or the expansion of the system. By contrast, the capital structure is a creation of MDU's management. There is no way of verifying that it will change in the manner MDU predicts. For this reason, most commissions use recent historical capital structures. Otherwise, MDU has the opportunity to game the regulatory system by projecting a more expensive capital structure, one with greater equity than now exists. A comparison of MDU's 2001 capital structure with its forecast 2003 capital structure reveals that this is exactly what MDU has done in this case. For this reason, an historical capital structure should be used in this case.

Cost of Debt

17. MDU's claimed cost of debt in 2001 is 9.302 percent, and its projected 2003 debt cost is 9.180 percent. These values are calculated on Exhibit 2, Statement F-1, pages 1 and 3. Those pages show only two debt issues, First Mortgage Bonds and Pollution Control Bonds, totaling \$133.5 million in 2001 and \$132.6 million in 2003.

18. Statement A, pages 11 and 12 of that same exhibit reveals that there is substantially more to MDU's debt than these two issues. As of December 31, 2001, there were \$405.2 million in senior notes, \$219.7 million in commercial paper, a

revolving line of credit of \$25 million, and term credit agreements of \$11.8 million. Using the cost values shown on those pages, King calculated that the blended cost of MDU's debt is 6.167 percent, more than 300 basis points lower than MDU proposes.

19. The difference between Staff and MDU revolves around what "the Company" actually is. According to MDU witness Keller, only the First Mortgage and Pollution Control bonds relate to MDU Utilities. All of the other debt pertains to Centennial Holdings, which holds title to the non-regulated operations of the parent Company, MDU Resources Group, Inc. The two sets of debt are not fungible. MDU has no access to Centennial's debt and vice versa.

20. On cross-examination, however, Keller made it quite clear that there is no such entity as the Montana-Dakota Utilities Company. The only legal entity is the parent Company, MDU Resources Group, and only that company can issue debt. Neither the utility operation nor Centennial has any debt in its own right.

21. At the hearing, Keller testified that MDU had attempted to build a "firewall" between the debt of MDU Utilities and that of Centennial. The purpose, he argued, was to protect the utility operations from the effect of default on Centennial's debt. He stated that if Centennial or one of its subsidiaries should go bankrupt, then the bankruptcy judge would not be able to "collapse the corporation" and gain access to the utility's assets. Keller stated that is the reason MDU does not commingle the funds raised for the utility with those raised for Centennial.

22. These are laudable objectives, but it is not clear how far they go. On cross-examination, Keller conceded that if the bankruptcy of either MDU's regulated or its unregulated operations caused the parent to declare bankruptcy, then the bankruptcy court would look at all of MDU's assets to satisfy creditors' claims, including those of the regulated utility.

23. King suggested that there might be another, less altruistic reason for attempting to isolate Centennial's debt from that of the utility operations. It is to ensure that ratepayers pay the very high costs of the First Mortgage bonds and receive no benefit from the Company's other, lower-cost financing resources. While the Company may have written its low-cost financing instruments to direct funds to Centennial and its subsidiaries, that was an artifice to "game" the regulatory system into ascribing only the highest cost debt to regulated service ratepayers. The Company could have used the Centennial funds anywhere had it written the debt instruments differently.

24. In the end, all of MDU Resources' debt is secured by all of MDU Resources' assets. This means that in the end, all of its debt is fungible. For this reason, the Commission finds it appropriate to use the blended cost of all of MDU Resources' debt as the cost of debt for MDU's utility operations.

Cost of Equity

25. MDU's rate-of-return witness, Dr. J. Stephen Gaske, has recommended a return to equity of 13.25 percent. This return was developed using three variants of the Discounted Cash Flow ("DCF") approach, plus a series of "benchmark analyses."

26. For his DCF results, Gaske drew a distinction between "Investor Requirements" and "Cost of Capital" based on his belief that stock flotation costs, equivalent to 4.75 percent of the return, must be included in the latter. Because MDU's parent company, MDU Resources Group, Inc., is heavily engaged in non-regulated activities Gaske used a "proxy group" of six companies based on Moody's utility series. His DCF results for these companies were as follows:

	Investor Requirements	Cost of Capital
Second-stage Retention Growth	11.94%	12.51%
Basic DCF	12.61%	13.21%
Primary DCF	12.63%	13.22%

27. Gaske's benchmark analyses consisted of four risk premium comparisons using historical differences in earned returns to equity from large and, alternatively, small companies relative to current yields on U.S. Treasury bonds and corporate bonds. He also identified the recent returns on per-share book value of S&P 500 corporations and Value Line's list of industrial companies. All of his benchmark indicators were higher than any of his DCF returns.

28. Gaske's final selection of 13.25 percent was based on his belief that the risk of MDU's gas distribution business is slightly higher than that of his proxy group of gas distribution companies. He based this belief principally on the smaller size of MDU relative to the proxy companies.

29. King recommended a very different return to equity: 10.5 percent. King followed most of the same procedures as Gaske using the DCF analyses as the principal analytical tool. Like Gaske, King used a comparison group of gas distribution companies. Also like Gaske, King used a forecast of next year's dividends for the dividend yield portion of the DCF formula. King also used both analysts' forecasts and the concept of earnings retention to calculate the growth component of that formula -- as did Gaske. Finally, both King and Gaske adjusted their final recommendations based on their assessments of the risk of MDU's gas distribution activities relative to that of the comparison companies.

30. The explanation for the dramatic 275 basis point (2.75%) difference between the recommendations of the two witnesses lies in the details of the application of the DCF formula. As used by both witnesses, the DCF formula is the sum of next year's dividend yield on MDU's stock and the expected future growth rate in its dividends and earnings.

31. The differences between the Gaske and King applications of the DCF formula relate to the following elements:

1. Inclusion of flotation costs;
2. Selection of comparison companies;
3. Forecast of next year's dividends;
4. Timing of analysts' forecasts;
5. Computation of earnings retention growth;
6. Presentation of the DCF results; and
7. Adjustment of comparison companies results to reflect MDU's risk.

Flotation Costs

32. Gaske drew a distinction between "investor requirement" and "cost of capital," with the difference being cost of issuing new shares in public stock offerings. Gaske quantified this cost as 4.75 percent, based on a representative sample of flotation costs incurred with 34 new common stock issues by natural gas transmission and distribution companies between 1992 and 2001.

33. King agreed with Gaske that flotation costs should be recovered, but he questioned the propriety of applying a ratio for these costs to the entire amount of common equity. Flotation costs are incurred only when a company issues new stock, and then only when there is a public stock offering. Existing stock incurs no flotation cost, and even new stock incurs no such costs if it is distributed as an employee or shareholder benefit either through options or as bonuses.

34. King noted that the effect of Gaske's flotation cost adjustment is to increase his equity return by 60 basis points, or .60 percentage points. When multiplied by the \$1.125 million book equity value of the MDU Resources, Inc., this allowance amounts to \$6.75 million annually, which is substantially more than the \$5.4 million in flotation costs that the Company has incurred over the past five years.

35. King suggested that if a flotation cost adder is to be used, it should be equal to a reasonable estimate of the annual flotation cost incurrence divided by the entire amount of the Company's equity. In MDU's case, annual flotation costs during the past five years have been about \$1.1 million. The Company's total book equity value is \$1,125 million, for a flotation cost allowance of 0.1 percent. This amount is so small as to be lost in the rounding. For this reason, he recommended no explicit flotation cost adder.

36. In rebuttal, Gaske distributed an exhibit that purported to demonstrate that failure to include flotation costs in the return of a company's stock trading at book value would result in the dilution of the book value of that company's shares. On cross-examination, however, Gaske admitted that all of King's comparison companies had per-share market values higher than book value, and that when such companies sell new stock,

the effect is to increase book value, not dilute it. On cross-examination, Gaske admitted that his approach to the issue of flotation cost in this proceeding was the same as his approach in Commission Case No. PU-399-01-186¹ involving MDU's electric rates. Gaske also agreed that most regulatory commissions do not allow a flotation cost adder.

37. The Commission rejects Gaske's flotation cost adder.

Selection of Comparison Companies

38. Both King and Gaske acknowledged that the heavy involvement of MDU's parent company, MDU Resources Group, Inc., in non-regulated activities effectively precluded using that company as the basis for finding the return to equity of its gas distribution business in North Dakota. Necessarily, this required the selection of companies whose primary business is gas distribution. Gaske picked six companies from Moody's list of natural gas distribution companies. King chose 11 companies from Value Line's Investment Survey based on the criteria that they must have investment grade bond ratings, total operating revenues over \$100 million, and derive more than 75 percent of their revenue from gas distribution services. The two lists are as follows:

King Comparison Companies	Gaske Proxy Group
Atmos Energy Corp.	AGL Resources
AGL Resources	Keyspan Corporation
Cascade Natural Gas Corp.	LaClede Group
LaClede Group, Inc.	Northwest Natural Gas
NICOR, Inc.	People's Energy Corp.
Northwest Natural Gas Co.	WGL Holdings, Inc.
People's Energy Corp.	
Piedmont Natural Gas Co.	
South Jersey Industries, Inc.	
Southwest Gas	
WGL Holdings, Inc.	

39. Five of Gaske's six companies are also represented on King's list. The exception is Keyspan Corporation, which King excluded because that company's gas distribution operations accounted for only about half its revenue. We find that King's choice of companies provides a broader and therefore more representative group of companies from which to draw indications as to the cost of equity for gas distribution operations.

¹ Order dated April 24, 2002, ¶ 15

Forecast of Next Year's Dividends

40. Both King and Gaske used a forecast of next year's dividends to identify the dividend yield portion of the DCF formula, and both witnesses based this forecast on a percentage of the 5-year annual earnings growth rate predicted by Zacks Investment Research, Inc. Only the percentage differed. King used a factor 1.5 on the assumption that the next dividend increase would be randomly distributed over the coming year. Gaske used a 1.625 inflator of the growth rate and argued that King's factor does not reflect the present value of next year's dividends and dividend increases. King responded that if he were to reflect the time value of next year's dividend, rather than simply its numerical value, he would reduce the inflator, not increase it as Gaske has done. The effect on the final DCF results of this .125 difference in the inflator for the next year's dividend is negligible. The Commission finds that, since the .125 difference in the inflator for the next year's dividend is negligible, no adjustment will be made for this issue.

Timing of Analysts' Forecasts

41. Gaske's testimony was filed on April 12, 2002, concurrently with MDU's initial application for an increase in its gas rates. The record does not disclose when Gaske prepared his testimony, but presumably it was in the months immediately preceding the application, which would be February and March of 2002. This would be consistent with the fact that the latest month shown on Gaske's presentation of bond yields is January 2002.

42. King filed his testimony on August 30, 2002, so his information on such factors as share prices and investor expectations was gathered approximately six months after Gaske's.

43. It is not clear how these differences in timing affect the results of the respective analyses. For example, Gaske reported Zacks' consensus 5-year earning growth forecast for the LaCledde Group as 12.0 percent. By the time King prepared his testimony, that forecast had dropped to 4.25 percent. On the other hand, Gaske's forecast growth rate for AGL Resources was 7.03 percent, while that reported by King was 11.42 percent. We find it is appropriate in this proceeding to use King's analysis that reflects more recent data than Gaske's analysis.

Procedure for Computing Retention Growth

44. Both King and Gaske used the same two methods for forecasting the growth component of the DCF formula. One was Zacks Investment Research's consensus forecasts of 5-years' earnings growth, and the other was the rate at which the retention of earnings would permit the book value of each share to increase over the coming five years. Both witnesses used Value Line's company reports for this procedure, although

again, King had access to later reports than did Gaske. The only methodological difference between the two analyses was King's inclusion of a factor to account for the sale of new stock at market values higher than book value. This inclusion added 100 basis points to the earnings retention growth model developed by King. Although Gaske did not include this factor in his retention growth model, he did not object to King's use of it.

Presentation of the DCF Results

45. Gaske purported to perform three different DCF analyses of his proxy group of companies. One of these analyses, the "basic DCF," was identical to King's "classic DCF" analysis. Both involved combining the forecast dividend yields with Zacks' 5-year consensus forecasts of earning growth.

46. While the methods were the same, the results were quite different. Gaske's six-company proxy group yielded a median basic DCF return, prior to flotation costs, of 12.61 percent and a mean return of 12.95 percent. King, applying exactly the same procedure to his comparison group of 11 companies, found the average (mean) to be 11.29 percent.

47. For his other application of the DCF approach, King added the dividend yield to the growth rate indicated by the earnings retention growth model for each of his 11 comparison companies and found the average to be 12.18 percent. Had Gaske done the same thing, he would have added his average dividend yield of 5.14 percent to his retention growth estimate of 5.5 percent for a DCF return indication of 10.64 percent.

48. Gaske diluted his retention growth rate by mixing it one third, with two-thirds represented by the Zacks' 5-year earnings forecasts. The result was quite close to the "basic" DCF indications. The median of his "Second-Stage Retention Growth DCF Calculation" was 11.94 percent, the mean 12.25 percent.

49. Gaske presented a third version of the DCF analysis. Gaske put forth what he called his "primary" DCF calculation. This was no calculation at all, but merely the adoption of a range of growth estimates pulled from thin air with no support in the data Gaske presents. The range was 6.75 percent to 7.75 percent, asserted by Gaske to have been based on such factors as the 5.5 percent growth in nominal Gross Domestic Product during the past decade, the expected demand growth for natural gas, and investor expectations. None of these considerations support a growth forecast in the range of 6.75 percent to 7.75 percent. The bottom of this range is well above the 5.5 percent GDP growth cited by Gaske, as well as the 5.5 percent growth indicated by his own earnings retention calculation. The top of the range is above the 7.56 percent growth rate predicted by Zacks for the six proxy group companies used by Gaske. This "primary" DCF analysis is biased upward.

50. King also presented a third DCF calculation, but he subsequently discarded it. King calculated a growth factor for each of his 11 comparison companies based on the each company's historical earnings growth between 1997 and 2001. While the average DCF indication of 11.72 percent might appear reasonable, the variation among the individual company observations was so great as to provide little or no probative value - as King conceded in his testimony.

51. The Commission finds that neither of these third DCF calculations should be given any weight.

52. In presenting his DCF returns, King went one step further than Gaske, and provided his estimate of the DCF return requirements of each of his comparison companies. He did not use a mechanical formula because, as he conceded in his testimony, precision is impossible. He described his procedure orally at the hearing as follows:

...what I have done in each case is taken the classic DCF return, which is probably the best estimator, and then turned and looked at the retention growth method. If the retention growth looks like it's totally out of whack with the forecast, and in some cases they are – simply no way that the company could be growing as fast or as slowly as the investor survey shows – I modified that classic DCF in the direction of the retention growth.

53. The results of King's procedure were as follows:

	Classic	Book Value Growth	King DCF Return
Atmos Energy Corp.	12.06%	14.42%	12.5%
AGL Resources	16.67%	11.53%	14.0%
Cascade Natural Gas Corp.	10.25%	15.11%	11.0%
LaClede Group, Inc.	10.29%	11.23%	10.5%
NICOR, Inc.	11.51%	15.96%	12.0%
Northwest Natural Gas Co.	10.65%	10.12%	10.5%
People's Energy Corp.	13.13%	12.07%	12.5%
Piedmont Natural Gas Co.	9.42%	11.24%	10.0%
South Jersey Industries, Inc.	8.15%	12.57%	11.0%
Southwest Gas	10.52%	8.53%	10.0%
WGL Holdings, Inc.	8.99%	11.21%	9.5%
Average	11.29%	12.18%	11.23%

54. Gaske rebutted the fact that the average of King's selected DCF results was lower than the average of either his classic or his book value growth results. This mathematical result stems from King's shrinking of the range of observations. King reduced the effect of the "outlier" highest and lowest observations. In absolute terms, the outliers on the high side diverge more from the mean than those on the low side,

even when their percentage difference from the mean is the same. This mathematical distortion can be avoided by focusing on the median observation of each series, that is, the observation where five values are higher and five are lower. The classic DCF median return is 10.52 percent, the median of the book value growth series is 11.53 percent, and the median of King's selected DCF returns is 11.0 percent. Additionally, it should be noted that in arriving at his final DCF recommended returns, King adjusted seven of the classic returns upward and only four downward.

55. On rebuttal, Gaske submitted two mechanical recalculations of King's DCF results, one using a 33%/67% weighting of the book value growth and Zacks' forecasts, the other using a 50%/50% weighting. Both yielded average returns considerably higher than King's 11.23 percent. In performing these calculations, however, Gaske excluded WGL Holdings, ostensibly because, with 74.6 percent of its revenue from regulated gas distribution, it falls outside King's 75 percent criterion. As Gaske admitted on cross-examination, 74.6 percent rounds up to 75 percent. His exclusion biased the results upward because, at 8.99 percent, WGL Holdings' classic DCF return was the lowest in King's comparison group. Moreover, Gaske never explained why his mechanical weightings of King's DCF results were more accurate or valid than King's analysis.

Adjustment of Comparison Company Results for MDU's Risk

56. King and Gaske disagree about the final adjustment each witness made to the DCF returns for his comparison companies to reflect the specific risk of MDU's gas distribution operations.

57. Having found that the DCF cost of capital (inclusive of flotation cost) for his proxy companies was in the range of 12.51 and 13.22 percent, Gaske selected 13.25 percent as MDU's capital cost. This upward adjustment from the range of proxy group returns was based on Gaske's belief that MDU's overall risks are slightly above-average relative to the proxy group.

58. King's adjustment was in the opposite direction. Having found that the average DCF return for his comparison group is 11.23 percent, King picked 10.5 percent for MDU, which is the midpoint between the group average return and the returns for the least risky companies in the group. The basis of this adjustment was King's belief that MDU is less risky than the comparison group.

59. In his initial testimony, Gaske discussed four types of risk: business risk, regulatory risk, financial risk and market risk. He found that MDU's regulatory and market risks are not significantly different than from those of his proxy group. MDU's financial risk is slightly greater because the bonds of MDU Resources Group are rated slightly lower than the bonds of the proxy companies. The major difference in risk, according to Gaske, relates to business risk. MDU's gas distribution operations are a fraction the size of the proxy companies. Those companies are between six and 46

times the size of MDU's gas distribution operations. Based on the historical difference between the earned returns of small and large companies, Gaske believes that MDU's smaller size might require a return more than 100 basis points (1.00 percent) higher than the proxy group. In addition, MDU faces the competition of propane and heating oil for new and existing load in its service territory. Furthermore, its rate structure recovers a substantial portion of its fixed costs in the volumetric component of its rates, and MDU does not have a weather normalization adjustment mechanism. On this basis, Gaske concluded that MDU's North Dakota gas distribution operations face somewhat greater overall business risks than the typical company in his proxy group.

60. King based his conclusion that MDU's gas distribution business is less risky than his comparison group on two facts. First, unlike eight of the 11 comparison companies, MDU's gas distribution operations have no non-regulated business activities. Second, MDU's equity ratio is higher than all but three of his comparison companies, suggesting a lower level of financial risk. He argued that a good case could be made for setting MDU's rate of return at the bottom of the scale of DCF returns for the comparison companies. However, in light of the possibility that the return set in this case may be in effect for an extended period into the future, he selected the midpoint between the lowest returns in his comparison group and the average.

61. In his rebuttal testimony, Gaske argued that King had failed to demonstrate any strong correlation between equity return and the equity proportion or the percent gas distribution revenues in his comparison companies. Gaske presented two correlation studies of these variables. One showed a weak, but measurable correlation between the percent equity in capital structure and King's estimates of DCF returns. The other showed no correlation between equity return and percent gas distribution revenues.

62. King conceded that neither of the two risk factors cited in his testimony are predictors of relative risk, but both are elements of relative risk. A high equity ratio is an indicator of low financial risk, and MDU's equity ratio is about equal to the highest of the equity ratios of within his comparison group. The relationship between financial risk and capital structure, which King cites in this portion of his testimony, was also discussed in Gaske's initial testimony at some length.

63. King noted that another element of risk is the amount of non-regulated activity. Regulated activities are less risky than non-regulated activities. When regulated earnings are short, MDU can come to the Commission for an increase in rates. If the Commission grants the rate increase, there is no question whether MDU can collect the additional revenue because of its monopoly status. That is not true of non-regulated activities, which by definition do not have the security of revenue recovery that low-risk regulated activities have.

64. King cited two further reasons that MDU gas distribution operations have lower risk than many of his comparison companies. Gas companies operating in warmer climates face competition from electric heating that MDU, operating in a cold climate, does not encounter. He testified that in Washington, DC, the Washington Gas Light

Company has lost two-thirds to three-quarters of the commercial load to the electric company. For residential customers, heat pumps can combine heating with air conditioning and so compete with gas.² King stated that stand-alone heat pump units that do not draw heat from groundwater will not work in North Dakota's climate because they have to be supplemented with electric resistance heating when temperatures fall below about 45 degrees Fahrenheit.³

65. The other difference cited by King relates to the intrusion of gas suppliers into the retail gas market. Some of his comparison companies (he cited Washington Gas and Atlanta Gas Light Company) are required to deliver the gas of independent suppliers. The extreme example is Atlanta Gas Light, which no longer buys gas on behalf of its customers. Instead, merchant gas suppliers buy the gas, and Atlanta Gas Light delivers it to end users on behalf of the suppliers. He testified that Atlanta Gas went from some 600,000 customers to 11. When one of these gas suppliers went bankrupt, Atlanta Gas was "stiffed" for several million dollars.⁴ In another example cited by King, Washington Gas has lost two thirds of its commercial load to competitive suppliers. The suppliers have failed to acquire the transportation capacity that Washington Gas had maintained to serve those lost customers, and there is now a risk that in a cold winter, the suppliers will not be able get the required gas to Washington.⁵

66. King observed that MDU does not the active competition from suppliers that larger companies serving larger service territories have. It therefore does not face the severe business risks associated with these suppliers.

67. King stated that Gaske conducted an apples-and-oranges comparison regarding the alleged risk of small company operations. Gaske has compared the risk properties and required returns of large companies with those of small, stand-alone companies. King says that is not the proper comparison. King states that the relevant objective in this case is to find the risk characteristics of the gas operations of a large company. Being part of a large company provides the security of greater financial strength and also diversification of financial resources. King states that MDU's North Dakota gas distribution operations are not a small, stand-alone company, as are the small companies from which Gaske derives his 100 basis point small-company risk adder. MDU's North Dakota gas distribution operations are merely one part of the overall business of MDU Resources Group. That company is well within the size range of the companies in both King's and Gaske's comparison groups.

68. King stated that while MDU's gas distribution operations are small, they have a lower financial risk than do most of King's comparison companies by reason of a high equity ratio. They have no risky, non-regulated activities, as do most of the comparison companies. While MDU faces competition from propane and oil, as do virtually all gas

² At the hearing, Gaske submitted Exhibit 35, which contained some Washington Gas Light Company Internet advertisements for gas heating. These advertisements confirm that Washington Gas faces stiff competition from electricity for its residential heating load.

³ Tr. Oct 7, page 218

⁴ Tr. Oct 7 page 193.

⁵ Id.

companies, it does not confront effective competition for its heating load from electricity, as do the comparison companies that operate in warmer climates. Finally, MDU does not have the intrusion of independent gas suppliers into its retail market in anything like the degree that some of the comparison companies have. For these reasons, King's conclusion that MDU has somewhat less overall risk than his comparison companies is altogether reasonable.

69. We agree with King's conclusions and find that MDU has less overall risk than his comparison companies.

Gaske's "Benchmark Analyses"

70. Gaske presented two types of "benchmark analyses." In one series, he added the historical differences between Treasury bonds and corporate bonds, on the one hand, and earnings from the common stock of small and, alternatively large companies, on the other. The other benchmark analysis was to identify the recent earned return on book value of S&P's 500 companies and on Value Line's industrial companies. The results of these benchmark analyses are as follows:

Risk Premium Return Based on:

- U.S. Treasury Bonds	
v. Large Companies	13.3%
v. Small Companies	20.2%
- Corporate Bonds	
v. Large Companies	14.8%
v. Small Companies	22.2%

Alternative Investments

- S&P 500	21.5%
- Value Line Industrials	29.4%

71. Gaske appears to conclude from these tests that his 13.5 percent cost of capital, derived from DCF results, is quite conservative relative to these benchmark results. King argued that these comparisons are irrelevant. King argued that these results should be disregarded, because their conceptual basis is fatally flawed and the risk premium observations are without value statistically.

72. Gaske's risk premium analysis purports to measure the required return to equity by adding the historical difference in experienced earnings from stocks and bonds to the current levels of bond yields. These historical differences, as measured by Ibbotson Associates, go back to 1926. The theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials.

73. King observed that this theory is a statement of faith, not experience, and it defies logic. If investors' short term expectations are continually being frustrated (as has been the case during the last year), what logic supports the proposition that the sum of those failed short-term expectations represents a valid long-term representation of their expectations? King further argued that it is untrue that the differential in required returns between bonds and stocks is fixed and unchanging, as this theory postulates. The perceived safety/risk relationship of bonds differs from stocks, and their relative desirability as investment vehicles changes continually depending on such factors as inflation, economic growth, and the capital structures of the enterprises issuing the securities.

74. King stated that quite apart from this conceptual failing, the theory fails statistically. King referred to Exhibit 34 introduced by Gaske which shows annual returns to large company stocks, small company stocks and long-term corporate bonds, and it also shows their differences. King pointed out that the standard deviation of every one of these series is greater than the mean of the observations. King argued that the means therefore lack statistical significance and are useless as a predictive tool.

75. Gaske purports to demonstrate under his alternative equity investment analysis that MDU should be allowed a high return by observing that the returns to book equity on the S&P 500 companies from 1977 to 2000 have averaged 21.47 percent. He also observes that the book equity returns to 746 industrial, retail and transportation companies included in The Value Line Investment Survey have ranged from 27.57 percent to 31.75 percent over the five years 1996-2000. He argues that the average of 29.4 percent, along with the return of 21.47 percent experienced by S&P's 500 companies, suggests that the 13.25 percent he proposes for MDU is quite low.

76. King argued that these comparisons are irrelevant. He pointed out that investors in unregulated industrial, retail and transportation firms have no access to book equity value. The only value that is meaningful for investors in such firms is the market value. That is what an investor must pay to acquire the stock, and conversely, the value an investor will receive by selling the stock. Book equity value in an industrial firm is a purely historical number representing the dollars of original investment in equity capital contributed to (or retained by) the company. It has little relevance to the current market value, even for fairly capital intensive firms. Since most stocks sell well above their book value, the return that is accessible to investor is considerably less than the 20 to 30 percent noted by Gaske.

77. King noted that book values are relevant for regulated utilities because regulation makes them so. Regulation sets the earnings allowance for such companies relative to a rate base reflective of the book value of the capital invested utility operations. This condition does not apply to industrial firms.

King's Risk Premium Test

78. King did not attempt to find any absolute value of equity return using the risk premium approach. He agreed that equity investment, being inherently more risky than debt, requires a higher return. But rather than attempt the difficult (and arguably impossible) task of measuring that risk premium, he looked to the trends in bond yields in comparison to past North Dakota Commission findings of equity return to gas companies. King stated that if it appears that bond yields have increased, but he has recommended a reduced return to equity, then there may be reason to question his finding. On the other hand, if his proposed equity return tracks with the changes in bond yields, then there is at least a "sanity check" on the propriety of his finding.

79. King identified three gas cases during the past 12 years in which the Commission had found a rate of return to equity. He compared those rates of return with the then-current yields on 10-year Treasury bonds and Aaa Corporate bonds. He then identified the current (that is, August 2002) bond yields. The results of his research are as follows:

Case	Utility	Date	ROE Allowed	10-Yr Treas.	Aaa Corporate
399-90-820	MDU	July 30, 1991	12.0%	8.27%	9.00%
400-95-559	NSP	June 7, 1996	12.0%	6.91%	7.71%
400-00-521	NSP	June 27, 2001	11.5%	5.28%	7.18%
399-02-183	MDU	August , 2002	10.5%*	4.35%	6.45%

80. We find that, while King's recommended equity return is lower than any that have been approved for gas utilities in the past 12 years, the evidence of lower overall capital costs justifies this result. Those lower capital costs are demonstrated by a dramatic reduction in bond yields relative to their level when the previous gas rate cases were decided. For this reason, we find that King's recommended equity return of 10.5 percent is reasonable.

Depreciation

81. Staff has determined that test year depreciation expense should be reduced by \$2,172,000. MDU's current depreciation expense is based on rates developed in a 1991 study performed by Stone & Webster. Staff witness Michael J. Majoros performed a series of studies that suggested MDU's depreciation rates are excessive. First, he found that annual depreciation accruals during the past five years have exceeded utility construction and acquisition by \$28.5 million. When common plant construction and acquisition is added, the five-year accruals still exceeded expenditures by \$409,000. While it is not the purpose of depreciation to fund construction, this comparison indicates that MDU has obtained substantial cash flow from depreciation. Majoros noted that in *Lindheimer v. Illinios Bell Telephone Company*, 292 U.S. 151 (1934), the

Supreme Court found that excessive depreciation results in the extraction of capital from ratepayers.

82. Majoros next observed that as of the end of 2001, the ratio of depreciation reserve to the original cost of distribution plant came to 70.7 percent. Based on his experience, this level of depreciation reserve is extraordinarily high and suggests that prior depreciation rates have been excessive. Majoros stated that the likely source of these excessive rates is the 140 percent negative salvage adjustment for Account 380 – Services.⁶

83. Majoros adjusted MDU's salvage factors based on an obvious inconsistency between the net salvage assumed in the Stone and Webster study and actual net salvage that MDU has experience during the past five years. The Stone & Webster study developed depreciation rates that resulted in a large recovery of "negative salvage," that is, cost of removal. Specifically, its depreciation rates were designed to recover total gas plant of \$102.5 million plus negative salvage (removal) costs of \$46.9 million.

84. Majoros found that MDU's actual net salvage experience has been positive. In every year since 1997, MDU has received more in salvage value for its retired gas and common plant than it has paid in removal cost. The total cumulative 5-year net positive salvage receipts for gas plant have amounted to \$1,444,452. For common plant, net positive salvage receipts have come to \$5,529,260.

85. We find that MDU has experienced positive net salvage.

86. To correct for over-recovery of net salvage, Majoros proposed to adopt the Stone & Webster lives and survivor curves for each account with no net salvage overlay. The account-by-account depreciation rates would thus represent pure depreciation, that is, solely the recovery of original cost. To recognize net salvage, Majoros proposed to deduct from total annual depreciation the average annual amount of net positive salvage for gas plant, plus the net positive salvage of common plant distributed between gas and electric operations based on their respective net salvage amounts. Total depreciation of test year plant would be \$1,937,000. The annualized positive salvage offset would be \$848,000, for a net test-year depreciation expense of \$1,089,000.

87. Majoros noted that, in addition to matching net salvage accruals with actual net salvage experience, his treatment of removal costs conforms with Generally Accepted Accounting Principles ("GAAP") as recently refined in Statement of Financial Accounting

⁶ Late Filed Exhibit 1 explains the source of the 140% negative salvage for the Service account. It compares the original cost of retired services with the cost of removal. The composite ratio of original cost to removal cost for all Services removed between 1996 and 2000 is 138%. The removed services date back to 1926, but all of the removal costs were incurred since 1996. The ratio is so high because it compares dollars spent up to 75 years ago with dollars spent only since 1996. The result is a ratio that captures the inflation that has taken place over the past 75 years. When that ratio is then applied to current plant balances to calculate depreciation expense, it effectively projects that same rate of inflation to the end of the current plant's life. Ratepayers are thus being forced to pay for future inflation that presumably will match past inflation. By charging ratepayers now for inflation in the future, this practice fails to recognize the much higher present value of current ratepayer dollars over the Company's future removal cost dollars.

Standards No. 143 (“FAS 143”). That standard, which MDU must adopt this year, requires companies to determine whether they have a legal obligation to retire property and incur the cost of removal or dismantlement. If they do, they must declare the present value of the future “asset retirement obligation” costs as a liability on their books to be amortized over the remaining life of the asset. If they do not, then the American Institute of Certified Public Accounts’ Statement of Position on Property, Plant and Equipment would require that these costs be expensed as they are incurred.

88. Majoros testified that MDU has not determined whether it has asset retirement obligations, or what the present value of those obligations might be. For this reason, Majoros’ adjustment reflected net salvage experience as a rolling five-year average of actual net removal costs.

89. In rebuttal, MDU witness John A. Jeter, a retired accountant from Arthur Anderson & Co. argued that Majoros had not done a depreciation study, that his review of the current depreciation rates is superficial and contains many errors, and that he has no basis for proposing changes in depreciation rates. According to Jeter, the current depreciation rates are based on a comprehensive study prepared in 1991 and used beginning 1994. He argued that no adjustment of depreciation rates should be entertained until the current depreciation study is completed and an appropriate review has taken place.

90. Jeter asserted that the 1991 depreciation study by Stone & Webster is a much more reliable source of information regarding net salvage than a cursory look at net salvage for all accounts over a five year period. Jeter did not explain the reason, nor did he refute Majoros’ observation that the Stone & Webster study had recommended large negative salvage allowances, while MDU’s actual net salvage experience has consistently been positive.

91. Jeter’s principal response was to attack Majoros’ net salvage proposal to adjust overall depreciation by \$848,000 based on the past five years’ actual experience. He argued that the net salvage amounts used by Majoros varied from year to year and that they reflected the sale of an office building for approximately \$4.6 million. Jeter also noted that the electric net salvage amounts – not at issue in this case -- included an insurance adjustment.

92. Jeter also argued that Majoros has allocated common property net salvage based on the direct net salvage amounts of the gas and electric operations, which is not the basis used by MDU. He failed to mention how MDU does allocate these common net salvage amounts. He concludes, “the proposed adjustment is not supported by any evidence and should not be approved.”

93. The variability of net salvage from year to year is the very reason Majoros used a five-year average of net salvage experience. Jeter never explained why it should be the basis for rejecting Majoros’ adjustment.

94. Jeter's statement that the Majoros depreciation adjustment is "not supported by any evidence" is incorrect. During his re-cross examination, Jeter read the following passage from the NARUC Public Utilities Depreciation Manual, dated August 1, 1996:

When estimating future net salvage, every effort should be made to ensure that the estimate is as accurate as possible. Normally, the process would start by analyzing past salvage and cost-of-removal data and by using the results of this analysis to project future gross salvage and costs of removal.

95. Majoros analyzed past salvage and cost-of-removal data and found that over the past five years salvage has consistently been greater than cost of removal for both gas plant and common plant. His adjustment reflects that finding.

96. MDU urges the Commission to defer any consideration of depreciation until its new depreciation study, currently being conducted by AUS Consulting, is completed by the end of this year.

97. The Commission believes that no element of MDU's revenue requirement should be exempted from this proceeding. MDU has specifically included depreciation expense in its application and has the burden to prove its case. Therefore, we reject the suggestion that we should decide all issues of MDU's applications with the exception of depreciation. Under N.D.C.C. § 49-05-06, the Commission must decide on the evidence before it by December 12, 2002. MDU's request to defer any consideration of depreciation until the new depreciation study is completed is denied.

98. MDU should not be permitted to continue to charge ratepayers depreciation expense that is excessive. A new depreciation study will not alter the fact that in recent years net salvage has consistently been positive, while the current depreciation rates incorporate a very large allowance for negative salvage.

99. MDU contends that over-depreciation is good for ratepayers. Had Majoros' adjustment been implemented in 1995, MDU's revenue requirement would be higher than it is now. MDU argues that the cumulative effect of overcharging depreciation is to reduce the rate base to the point where the reduction in return and income allowances exceeds the overstated depreciation expense. Jeter multiplied Majoros' \$2.172 million depreciation expense reduction by the 8 years since 1995 to derive a presumed increment in the rate base of \$17.376 million. He then calculates that at MDU's proposed 11.044 percent return and 39.61 percent tax rate, the revenue requirement increase from this rate base increment would be \$3.2 million, which is more than Majoros' depreciation expense reduction of \$2.172 million.

100. On cross-examination, Jeter admitted that MDU's plant in 1995 was smaller than it is now, so Majoros' depreciation adjustment would have been smaller if applied in 1995. Therefore, Jeter's calculation of the impact of over-depreciation is likely incorrect. Nevertheless, we find there is no justification for charging ratepayers depreciation in

excess of that determined under regulatory depreciation practices. Over-depreciation results in the extraction of capital from ratepayers and is improper from a legal, a regulatory, an economic, and an accounting standpoint.

101. We agree with staff's proposal for depreciation expense and its impact on test year rate base.

Operation and Maintenance Expense

Bonuses and 2003 Labor Expenses

102. Staff witness Majoros proposed to eliminate bonuses from the forecast test year and to hold test year labor costs to their 2002 levels. MDU included average bonuses for the years 1999-2001 in the amount of 6.1 percent of labor costs. Applied to the \$8,239,000 in labor costs in 2002, the bonus elimination comes to \$503,000. The 2003 labor cost increase eliminated by Majoros amounts to \$236,000. These direct labor cost adjustments reduce payroll taxes by \$40,000 in 2002 and \$60,000 in 2003.⁷

103. Majoros testified that given the state of the economy and the fact that MDU is requesting a rate increase, it would be unreasonable to include bonuses in the revenue requirement.

104. Majoros accepted the 2002 labor cost increase, but objected to extrapolating that increase through 2003. Majoros charted the overall pattern of operating and maintenance costs since 1996 and found that these costs remained relatively stable through the year 2000. Since that time they have since taken a sharp upturn, and MDU projects a 5.7 percent increase each year from 2000 through 2003. This rate of increase exceeds predicted inflation of 2.8 percent annually.

105. MDU witness, Richard D. Spratt, MDU's Vice President – Human Relations, testified on rebuttal. Spratt argued that bonuses are an integral part of overall compensation philosophy to remain competitive with other employers. Part of that compensation is intentionally put at risk in the form of bonuses that are paid on the basis of various goals, including the MDU's overall profitability. Spratt presented the results of an industry survey that showed most utilities pay bonuses not only to management employees, but to salaried and hourly employees as well. Spratt stated that the elimination of bonuses would risk rendering MDU uncompetitive relative to other employers.

106. The issue before the Commission is not whether MDU should pay bonuses or increase salaries. The issue that the Commission must decide is whether such bonuses and raises properly should be included as elements of a rate increase.

⁷ Calculated from the data presented on Exhibit 19, MJM-9, pages 1 and 2.

107. C. Wayne Fox, President of MDU Utilities Company, stated that from 1994 through 2001 the Consumer Price Index has risen nearly 20 percent, and in spite of that increase MDU has been able to hold the line on gas rates by finding ways of operating the business more efficiently and taking advantage of new technology. MDU even reduced its rates in 1999, and it did this through improved efficiency. Fox testified that MDU has reduced its employees by 30 percent since 1994. In that year there were 248 customers per MDU employee. In 2001, one employee was serving 370 customers. Then suddenly, beginning in 2001, MDU lost its ability to stay ahead of inflation. MDU's rate increase application not only implies but asserts that this loss of efficiency will continue through 2003. MDU witness, Rita Mulkern testified that while all the past employee reductions are reflected in the 2001 base period data, no further reductions are forecast for 2002 and 2003.⁸

108. During her examination of Mulkern, Commissioner Wefald alluded to the possibility that the Commission might want to give MDU an incentive to practice savings and to find ways to achieve new savings.⁹

109. We find that MDU's rate increase application provides no incentives to improve efficiency. The deterioration in productivity improvement during the years 2001 and 2002 is simply extrapolated into 2003. MDU should not be encouraged to perpetuate its own loss of efficiency. While the 2002 increases in labor costs should be allowed because they have already happened, no further deterioration of labor productivity should be built into the revenue requirement imposed on ratepayers. For this reason, the 2003 labor cost increase are disallowed.

110. The same objective of incentivizing MDU to regain its previous levels of productivity improvement applies to bonuses, only here the incentives apply directly to employees. Apparently, a significant portion of MDU's bonuses is granted on the basis of MDU's overall profitability. Spratt testified that two years ago, presumably in 2000, 75 percent of MDU's employees received 7 percent bonus. Last year, 2001, their bonus was 0.6 percent.¹⁰ Presumably, these bonus levels reflected the fact that in 2000, MDU earned 11.96 percent on its North Dakota Gas Operations, but in 2001, it earned only 1.6 percent.

111. If profitability drives bonuses, as it appears, then it is altogether inappropriate to include bonuses in a revenue requirement that drives a rate increase. The reason MDU needs the rate increase is that it is not profitable. If it becomes profitable as a result of a rate increase, that profitability will not have come about because the employees have performed particularly well. To the contrary, it will be because the employees have not performed well, and MDU needs rescue from the Commission.

112. We find that the revenue requirement imposed on ratepayers should not include rewards for poor performance. For this reason, bonuses should be disallowed.

⁸ Tr. Oct 8, page 473.

⁹ Tr. Oct 8, page 475.

¹⁰ Tr. Oct 8, page 510.

SISP Costs

113. The Supplemental Income Security Plan (“SISP”) is a plan that provides supplemental pension benefits to key employees. “Key employees” are officers, directors and senior managers of MDU Resources and MDU Utilities. The plan is expected to cost \$259,000 in 2002 and \$265,000 in test year 2003.

114. SISP was initiated in 1982, but MDU never sought its inclusion in revenue requirement until Case No. PU-399-01-186. In its April 24, 2002 decision in that case, the Commission accepted Staff’s observation that this plan benefits only the top few employees, those that are already quite well paid. The Commission concluded that it is inappropriate for ratepayers to bear the expense of the SISP costs.¹¹

115. MDU witness, Richard A. Espland, acknowledged that his testimony was essentially the same as it was in Case No. PU-399-01-186.¹² Espland acknowledged that SISP benefits only MDU’s high salaried employees with income ranges from a low of \$75,000 to its president at around \$250,000 to \$300,000.¹³ Espland also agreed that none of the Public Utility Commission’s in the jurisdictions where MDU provides natural gas utility services have approved a ratepayer funded SISP program.¹⁴ The Commission took administrative notice of the Findings of Fact, Conclusions of Law and Order in Case No. PU-399-01-186.

116. We find that the exclusion of SISP was appropriate in Case No. PU-399-01-186, and the exclusion of SISP is even more appropriate in this case. Case No. PU-399-01-186 was a Staff-initiated proceeding to reduce MDU’s electric rates. This case is a MDU-initiated rate increase proceeding. As noted earlier, one of the reasons MDU seeks to increase rates after an eight-year period of price stability is a result of management’s failure to maintain its previous rate of productivity improvement. The management personnel who are most responsible for this failure are the very employees who benefit from SISP. This is not the time to reward them at ratepayers’ cost. For this reason, the SISP expense should be disallowed again in this case.

Rate Case Expense Amortization

117. MDU proposes to amortize \$168,000 in rate case expenses over three years at \$56,000 per year. Staff witness Majoros proposes to amortize the same amount over five years at \$34,000 per year, for a difference in annual cost recognition of \$22,000. Mulkern suggested that if the five-year amortization is adopted, the unamortized balance should be included as a rate base addition.

¹¹ Case No. PU-399-01-186, Findings of Fact, Conclusions of Law and Order, April 24, 2002, ¶68.

¹² Tr. Oct 7, page 148

¹³ Tr. Oct 7, page 151

¹⁴ Tr. Oct 7, pages 151-152

118. The basis of Majoros' proposal is the historical period between rate cases. Fox stated in his direct testimony that MDU's last rate increase, in Case No. PU-399-94-297, was decided in 1994, and a rate reduction occurred in 1999 in Case No. PU-399-96-325. This represents two rate cases in eight years, or one every four years. MDU has rounded down to three, and Staff has rounded up to five.

119. We find that there is an important reason for adopting a longer, rather than a shorter amortization period for rate case expenses. Once an amortization becomes embedded in the revenue requirement, it remains there until a new revenue requirement has been calculated resulting in the very real possibility that MDU will over-collect its rate case expenses. MDU is protected from under-recovery of rate case expenses in the event it has another rate case in less than five years, because the amortization can be continued in the new rate case so that MDU ultimately recovers its costs, but only its costs. We find that 5 years is the appropriate amortization period for rate case expenses.

General Inflation Adjustment and Other Unadjusted O&M Expenses

120. In 2001, MDU incurred \$89,780,000 in O&M expenses, of which \$76,842,000 represented the cost of acquiring gas. Of the remaining \$12,938,000 O&M cost relating to distribution, MDU developed specific forecasts for \$9,249,000 based on projected changes for various categories of costs, e.g. labor, benefits, insurance, advertising. This left a catch-all category of \$3,689,000 of "other" O&M costs, which MDU assumed would increase between 2001 and 2003 by 2.8 percent annually, the assumed rate of general inflation.

121. Majoros noted that the Commission had never previously allowed this sort of inflation-based adjustment, and he recommended that it not start now. The elimination of this adjustment reduces test-year expenses by \$209,000.

122. Of the \$3,689,000 in 2001 costs within the "other" O&M category, \$1,709,000 is non-labor Administrative and General costs. The second largest component of the "other" O&M category, accounting for \$981,000 in 2001, is Customer Accounts, a portion of which is accounts receivable.¹⁵ We find that accounts receivable should not vary by general inflation, but rather by the overall size of the total amount billed to customers, including the cost of gas. As demonstrated graphically in Mulkern's rebuttal exhibit RAM-2, gas prices spiked in the last months of 2000 and the first months of 2001, but have since moderated, falling to levels equal or below their 1999 values.¹⁶

123. MDU's proposal to increase "other" O&M costs at the rate of inflation through 2003 is rejected.

¹⁵ Tr. Oct 8, page 469.

¹⁶ Exhibit 25, RAM-2.

Earnings

124. The Commission finds the following summary of fair and reasonable test year revenue and expenses:

	(ND Thousands)
<u>Description</u>	<u>2003 Test Year</u>
Sales	\$67,962
Transportation	900
Other	287
<u>Total Revenues</u>	<u>\$69,149</u>
Cost of Gas	\$50,072
Other O & M Expense	\$13,109
<u>Total O & M Expense</u>	<u>\$63,181</u>
Depreciation	\$1,089
Taxes Other Than Income	\$1,292
Current Income Tax Expense	(\$529)
Deferred Income Taxes	\$1,612
<u>Total Expenses</u>	<u>\$66,645</u>
<u>Net Regulated Income</u>	<u>\$2,504</u>
<u>Income Tax Calculation:</u>	
Net Income Before Taxes	\$3,587
Less Interest Deduction:	
Rate Base	\$20,767
Weighted Cost of Debt	3.081%
<u>Calculated Interest Deduction</u>	<u>\$640</u>
Other Tax Adjustments	\$4,282
<u>Taxable Income</u>	<u>(\$1,335)</u>
Combined Tax Rate	39.61%
<u>Income Tax Expense</u>	<u>(\$529)</u>

125. The Commission finds that for the 2003 test year, MDU has excess revenue of \$1.402 million as follows:

<u>Description</u>	(ND Thousands)
	<u>2003 Test Year</u>
Average Rate Base	\$20,767
ROR Required	7.979%
Return Required	\$1,657
Return Earned	\$2,504
Return (Excess) Deficiency	(\$847)
Tax Factor	1.656
Revenue (Excess) Deficiency	<u>(\$1,402)</u>

Cost Allocation and Rate Design

Class Cost of Services Study

126. A class cost of service study is an analysis of the embedded or incremental costs of providing utility services to the customers or classes of customers that either cause these costs, or to whom these costs can reasonably be allocated. The purpose of a class cost of service study is to provide an indication of what it costs to provide utility service to each customer class. In prior rate applications the Commission has used class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers.

127. MDU Witness Tammie Aberle sponsored an embedded cost of service study for the year ended December 31, 2001. This study allocated all of MDU's recorded distribution, general and gas-related common plant among seven categories of customers:

- Residential
- Firm General
- Air Force
- Small Interruptible Sales
- Small Interruptible Transport
- Large Interruptible

128. The costs allocated to the respective customer classes were in turn subdivided into three categories:

- Capacity related costs that vary with the amount of gas sendout on the peak days of the year. Examples include the sizing of distribution mains and meters to account for the maximum volume of gas handled on any one day.

- Throughput related costs that vary with the total amount of gas distributed throughout the year. Uncollectible accounts is a good example of this type of cost.
- Customer related costs that vary with the number of customers. Examples include the cost of meters, services and billing.

129. The only controversy relating to this cost of service study concerned the allocation of the cost of mains. Mains constitute 39.1 percent of MDU's gas distribution plant, but their relevance exceeds even this percentage. That is because general and common plant, which account for another 20 percent of total plant, are allocated as overheads to the direct investment, of which mains are the largest component.

130. In its initial cost of service study, Statement M of Exhibit 2, MDU allocated mains 64 percent on the basis of peak two-day throughput during the year and 36 percent on the basis of the number of customers.

131. King objected to the allocation of a portion of mains costs on a customer count basis. The arguable justification for doing so is that the purpose of the mains system is to reach customers, and that when more customers are added, the mains system has to be extended. King argued that this is true only at the very edges of the system, where gas mains are being extended to serve new developments in previously unserved areas. Even then, the added cost of mains for new customers can vary dramatically depending on the location of those customers.

132. King testified that another purpose of mains is to deliver gas. He argued that the value derived and the benefits received from the mains system are more related to the amount of gas delivered than to the number of customers. One customer receiving twice as much gas as another customer enjoys exactly twice the BTU heating content. The two cannot be equated in terms of benefit received, yet that is what a customer allocation of mains does. He illustrated his point by using the example of a section of main that changes the number and makeup of customers over a period of several years, but the amount of gas delivered remains the same. The weighting of that main in the cost of service study would change under a customer allocation, but it would remain the same (although shifted among customer classes) if the allocation were made on the basis of annual throughput.

133. King therefore asked that MDU conduct an alternative study to allocate half the mains cost according to the classes' two-day peak throughput and half on the basis of annual throughput.

134. On rebuttal, Aberle objected to King's revisions, arguing that main additions are not made only on the edges of the system to provide new service to developments, but are also required to enhance system integrity and maintain pressure throughout the system as customer additions are made. She objected that heating content has no impact on the cost of the mains system. She also objected to the use of a peak-day allocator that assigns costs to the interruptible class and a throughput allocator that

assigns costs to the transmission customers. She argued that both of these allocations violate practices previously approved by the Commission. She submitted yet a third cost of service study, one which allocates mains based 50 percent on throughput at the distribution level and 50 percent on peak day use by firm customers.

135. The results of the three cost of service studies show the rate of return from each customer class as follows:

	MDU Statement M	King CWK-7	Aberle TAA-4
Residential	3.083%	7.731%	6.367%
Firm General	3.998%	2.161%	1.106%
Air Force	50.281%	3.502%	69.369%
Small Interruptible Sales	83.992%	38.040%	40.905%
Small Interruptible Transport	169.437%	48.490%	57.738%
Large Interruptible	78.644%	-0.673%	27.320%
Total North Dakota	6.439%	6.442%	6.442%

136. As noted earlier, the Commission has used class cost of service studies as guidelines for rate design and as one of the factors in setting rates for the respective classes of customers. We appreciate the information provided by each of the studies because it quantifies the impact that a change in allocation factor has on the rates of return from customer classes. The studies also show that, regardless of the allocator used to allocate mains to customer classes, some customer classes are providing a much higher return on MDU's investment to serve than are other customer classes. In all three studies, the small interruptible customers generate a much higher than average rate of return.

Rate Design

137. In its initial application, MDU made a number of rate design proposals, as follows:

- Increase residential and firm general service rates by 4.6 percent, reduce the small interruptible class rates by 4.1 percent, and leave the Air Force and large interruptible rates unchanged;
- Separate the commodity rate into a Distribution Delivery Charge and a Cost of Gas charge, eliminating the Purchased Gas Cost Adjustment;
- Eliminate the declining block rate form from the commodity charges and substitute a flat per-dekatherm ("dk") rate;
- Change the customer, or "Basic Service Charge" from a monthly to a daily charge;
- Increase the Basic Service Charges by very large percentages, for example, the residential charge increases from \$6.50 to \$11.70, the small firm service charge from \$8.50 to \$24.00 and the large firm service charge from \$17.00 to \$51.00.
- Eliminate the residential seasonal rate;

- Increase the penalty for failure of interruptible customers to interrupt from \$10 to \$50 per dk;
- Increase the return check fee to \$20;
- Increase the reconnection fees for seasonal customers to match the avoided Basic Service Charges;
- Increase the reconnection charge for disconnected customers for nonpayment to \$30;
- Modify the Firm Gas Extension Policy Rate 120 and 124 to reflect MDU ownership of all prospective service lines.

138. King recommended that the Commission accept a number of these proposals regardless of whether MDU's overall revenue is increased, decreased, or remains unchanged. These consensus proposals are as follows:

- The commodity rate should be separated into two clearly distinct rates, the Distribution Delivery Charge and the Cost of Gas Rate.
- The declining block rates should be eliminated, and the revenue collected through the higher initial block rates should be reallocated to the Basic Service Charge.
- The residential seasonal rates should be eliminated, since there are no customers on these rates.
- Penalties for failure to interrupt should be increased, since MDU apparently believes that the current penalties are not sufficient to ensure that interruptible customers respond to their calls for interruption or curtailment.
- The reconnection charges for seasonal customers should be adjusted to match the higher Basic Service Charges resulting from the elimination of declining commodity blocks.
- MDU's proposed modifications to the line extension policy should be adopted.

139. King supported MDU's proposal to eliminate declining block commodity rates on the grounds that this rate structure implicitly encourages customers to use more gas, and it thereby discourages conservation. To the extent that it collects fixed customer costs in the commodity rate, it misstates the cause of the costs. Declining block rates also allow customers who use minor amounts of gas for non-heating purposes to escape the cost of providing the basic elements of service to them. We find that the declining block rate should be eliminated to more closely reflect cost causation in rates to customers.

140. Using MDU's billing unit counts for the year 2001, King calculated the revenue-neutral increase in monthly customer charges that would result if the present declining block rate structure were eliminated from each rate schedule, as follows:

	Present	Proposed
Small Residential	\$6.50	\$8.43
Large Residential	\$13.00	\$15.31
Small Firm Service	\$8.50	\$14.34
Large Firm Service	\$17.00	\$45.16

141. The Commission finds that, at a minimum, the monthly customers charge level should be at the amounts shown in the previous table to produce revenue-neutral levels for eliminating the present declining block rates.

142. King also recommended that the Commission consider MDU's proposal to convert the customer charges from monthly to daily charges. This proposal simplifies the calculation of the charge when customers are taking gas for only part of a month. We agree that MDU's monthly customer charge should be converted to a daily customer charge as proposed.

143. King recommended that the Commission reject MDU's proposal to increase the reconnection charge for discontinued service to \$30. While MDU claimed that this is a cost-based rate, King suggested that there is a legitimate public policy reason for not increasing this rate. The customers to whom this charge applies are almost certainly the lowest income customers. Otherwise, they would not have been disconnected. Since they have to pay their arrearages anyway, they are likely to be suffering some difficulty getting reconnected. To impose on them yet more cost, such as an increase in the reconnection fee, might prevent some of these customers from obtaining vital utility service. MDU did not respond to King's recommendation. We find MDU's proposal to increase the reconnection charge should be denied.

144. MDU proposed that residential and firm general service customers receive a rate increase of 4.6 percent, that the Air Force and large interruptible customers receive no increase, and that the small interruptible class receive a reduction of 4.1 percent. King pointed out that the Commission's past practice has been to recognize differences in class rates of return by approving lower rate increases to classes with the highest rates of return. It has not approved rate reductions to some classes when most customers are suffering rate increases. We find that all classes, regardless of their rates of return, should receive some rate increase if overall revenues are increased and a rate reduction if overall revenues are reduced.

145. King had similar misgivings about MDU's proposal to increase customer charges dramatically, even for the classes for which it was proposing rate reductions or no rate increases. MDU witness Russell Feingold argued that shifting revenue recovery from the commodity to the customer component allows MDU to recover much more of its fixed costs on a non-weather sensitive basis. He asserted that this shift also protects customers from the volatility in their gas bills caused by variations in weather.

146. King was concerned with the issue of rate continuity. The sort of changes proposed by MDU would result in dramatically different bills for different types of customers. Very low-use customers might find the increases in their average monthly bills extortionate. Customers accustomed to low gas bills in the summer, that possibly offset high electric bills, could be surprised by the sudden jump in their gas invoices.

147. King was concerned that customers may also resent high monthly customer charges. When most of the cost of gas is based on the level of gas consumption, customers can avoid high gas bills by conserving gas. But no amount of conservation permits a customer to avoid a monthly customer charge. As long as this charge is not a major portion of the bill, it is likely to be acceptable to most customers. But if it looms as a major element in the cost of gas, customers will come to regard it as a tax from which there is no escape.

148. King recommended that customer charges should not be increased by more than twice the overall increase. This ceiling on customer charge increases would be in addition to the increases in customer charges that result from the flattening of the declining block rates. If rates are reduced, the reductions should be flowed entirely into the commodity component of each rate schedule. Customer charges should not be increased when rates are reduced, except to eliminate the declining block feature of the rate schedules.

149. The Commission agrees with King's recommendation concerning customer charges.

Distribution Delivery Stabilization Mechanism

150. If the Commission disapproves of MDU's dramatic increases in customer charges, MDU proposes that, as an alternative, the Commission adopt a Distribution Delivery Stabilization Mechanism ("DDSM"). As described by Feingold, the DDSM would modify the effects of weather variations by adjusting bills for the difference between the actual heating degree days and heating degree days under normal weather. Following a cold winter, the excess in each class's revenue from the greater number of heating degree days would be divided by the projected annual sales volumes in that class and credited to all customers over the following year on a per-dk basis. The revenue shortfall from a warmer than normal winter would similarly be collected through a surcharge to all customers during the subsequent year.

151. Staff has gone part of the way toward MDU's objective of increasing customer charges. Staff has recommended that the commodity rates be flattened, and the revenue previously collected in the high initial blocks be recovered through increased customer charges. Staff has also recommended that any overall revenue increase be tilted toward the increased customer charges, and any overall rate decrease be flowed through entirely to the commodity charges. At the hearing, Aberle, MDU's rate design witness, could not say whether these concessions to MDU's target of increasing

customer charges relative to commodity charges were sufficient to persuade MDU to withdraw the DDSM proposal.

152. King testified that the value of a weather normalization adjustment should be to ameliorate the volatility in customer bills caused by variations in weather, and particularly the effect of unusually cold winters. In such winters, ratepayers typically experience a “double whammy.” First, they consume more gas than usual, which increases their bills even if the price of gas remains the same. Then, because cold winters are usually a widespread phenomenon, the demand for gas is higher across the continent, which means that the price of gas is higher. The result is a further inflation in their bills. Just this sort of inflation occurred across the country during the winter of 2000-2001.

153. King suggested that MDU’s proposal could result in a “triple whammy.” If North Dakota experiences an unusually warm winter, and it is followed by an unusually cold winter, ratepayers during the cold winter, already hard-hit, would find themselves paying a surcharge to make up for the shortfall in revenue collections in the previous year. The effect of MDU’s program could be to increase, not decrease the volatility in customers’ bills from year to year.

154. The Commission finds that MDU’s proposal should be denied because of its delayed effect. For a weather normalization adjustment to be beneficial to ratepayers and not just the utility, it must affect their bills when the unusual weather is occurring, not after it has occurred.

From the foregoing Findings of Fact, the Commission makes its:

Conclusions of Law

1. The Commission has jurisdiction over the parties in and the subject matter of this proceeding.
2. MDU is entitled to rates and charges necessary to provide it an opportunity to earn a reasonable rate of return on its North Dakota electric property, used and useful, for the service and convenience of the public in North Dakota.
3. MDU’s existing natural gas rates yield excess revenues of \$1.402 million per year.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes its:

Order

The Commission orders:

1. MDU shall implement a rate reduction sufficient to produce a total annual rate revenue decrease of \$1.402 million.
2. MDU shall file revised tariff sheets reflecting the rate reduction to be effective for natural gas service rendered on and after January 1, 2003.

PUBLIC SERVICE COMMISSION

Anthony T. Clark
Commissioner

Susan E. Wefald
President

Leo M. Reinbold
Commissioner