DIRECT TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 34-year history, members of the firm have participated in over 1000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Advocacy Staff of the North Dakota Public Service Commission.

Q. WHAT SUBJECTS DOES YOUR TESTIMONY ADDRESS?

A. My testimony addresses three broad subjects. Part I addresses the revenues, expenses and rate base that Montana-Dakota Utilities, Inc. ("MDU" or "the Company") has claimed for its two test years, 2004 and 2005. Part II develops the appropriate rate of return on the rate base associated with the North Dakota gas distribution activities. It concludes with my recommendation as to the level of rate relief to which the Company is entitled. Finally, Part III discusses issues of class cost allocation, rate design and Company's proposed Distribution Delivery Stabilization Charge.

Q. WHAT IS THE COMPANY SEEKING WITH RESPECT TO THE THREE BROAD SUBJECT AREAS?

A. Although the Company earned 9.55 percent on its rate base in 2003,[1] it claims that unless rates are increased, its return on rate base will decline to 3.332 percent in 2004 and 0.244 percent in 2005. The Company is seeking an authorized rate of return on rate base of 9.887 percent, inclusive of a 11.5 percent return on the 51.9 percent of its capital that is common equity. To achieve its proposed rate of return, the Company contends that its 2004 rates must be increased by $1,870,978 annualized and its 2005 rates by $3,334,226.

[1] Net operating income of $1,886,617 (Statement L, page 1) divided by rate base of $19,755,709

Based on a projected 2005 cost of service study that shows a negative return on residential service and very high returns on the Air Force and interruptible services, MDU proposed to increase residential rates by 3.5 percent, firm general service rates by 2.3 percent, and to hold Air Force and Interruptible rates at their present levels.

Finally, the Company proposes a Distribution Delivery Stabilization Mechanism that would adjust customers' bills for normal weather. Under this proposal, class rates will be adjusted each year for the departure from normal weather experienced the previous winter. Thus, if the weather is colder than normal in the winter of 2004-2005, customers would receive a surcredit on their bills beginning in May, 2005 for the effect of the Company's over-collection of revenue due to that cold weather.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO EACH OF THESE ISSUES?

A. Yes. As regards revenue requirements, I have identified one revenue adjustment, eight expense adjustments and one rate base adjustment that result in the Company's earning and adjusted 7.440 percent return on rate base in 2004 and 6.177 percent return on rate base in 2005. I have applied all of the Commission's findings as to rate of return in last MDU gas case, Case No. PU-399-02-183. In that case, the Commission included short-term debt in MDU's capital structure, and I have done likewise, using the quarterly balances of this debt at the end of the last four quarters. When current data are applied to the Commission's findings as regards return to equity, the result 8.8 percent, which I have rounded up to 9.0 percent. The composite rate of return to rate base is 7.926 percent.

When 7.926 percent is used as the target return and applied to the adjusted revenue requirements calculation, the indicated revenue deficiencies are $162,000 in 2004 and $603,000 in 2005.

I find that 70 percent of mains costs are fixed relative to peak gas volume, and I allocate that proportion among customer classes based on the respective class's total annual consumption of gas. While this allocation does not reflect cost-causality, neither does the Company's allocation on a customer count basis. Annual gas consumption reflects instead the total value of gas service to the respective customer classes. This reallocation reduces the disparities among class rates of return exhibited by the Company's study, but it does not eliminate them. Accordingly, I recommend that the Company's proposed increases in Basic Service Charges be adopted, and any remaining revenue requirement be captured in the per-dekatherm Distribution Delivery Charges to the firm service customers.

I object to the Company's proposed Distribution Delivery Stabilization Mechanism on the grounds that the delay in the weather normalization adjustment could exaggerate, rather than diminish, the weather-related fluctuations in the Distribution Delivery Charge. I recommend instead a DDSM that operates on a real-time basis by applying a weather- related adjustment to the customers' current bills.

PART I – REVENUES, EXPENSES AND RATE BASE

Q. WHAT RATES ARE AT ISSUE IN THIS PROCEEDING?

A. The rates that are at issue in this proceeding are the rates that MDU charges for distributing gas to its customers in North Dakota. These rates principally cover the cost of operating and maintaining a system of gas mains and services that transport gas from the interstate pipelines to the customers' premises. They do not cover the cost of the gas itself, nor do they cover the cost of transporting and storing gas prior to its delivery to MDU's distribution system. These latter costs,

which are recovered through the Purchased Gas Cost Adjustment ("PGCA"), are not at issue in this case.

In 2003, revenues from the North Dakota gas distribution charges at issue in this case were $21.2 million, or slightly over 20 percent of the total North Dakota revenues, including the cost of gas, of $103.1 million.

Q. HOW DOES THE COMMISSION DETERMINE WHETHER MDU NEEDS TO INCREASE ITS GAS DISTRIBUTION RATES?

A. The Commission identifies a test year jurisdictional revenue requirement and compares that amount with the jurisdictional revenues the Company will receive during the same test year. If the revenue requirement is greater than the revenues, then the rates are increased sufficiently to recover the revenue requirement.

Q. WHAT DO YOU MEAN BY "JURISDICTIONAL" REVENUES AND REVENUE REQUIREMENT?

A. In spite of its name, there is no corporate entity known as Montana-Dakota Utilities Company. Montana-Dakota Utilities is the public utility division within MDU Resources Group, Inc.[2] Aside from operating the utilities division, MDU Resources Group has a wholly-owned subsidiary, Centennial Holdings, which in turn owns subsidiaries engaged in gas pipeline service, construction and construction products, and foreign utility operations.

The MDU utilities division provides both gas and electric utility services, and it operates in five different states. All of this means that "jurisdictional" revenues and revenue requirements in this case are:

- the utilities division of MDU Resources,

[2] Great Plains Natural Gas is another utility division within MDU Resources and is considered as part of Montana-Dakota Utilities Co. for purposes of this case.

- the gas portion of the utilities division, and
- the North Dakota portion of the gas utilities division.

Fortunately, most of the revenues at issue in this case are discrete to North Dakota gas operations. They are collected from residents and businesses in North Dakota under the P.S.C. gas tariff schedules. A substantial portion of the plant is discrete to North Dakota as well. It consists of "*situs"* mains, services, regulator stations and meters physically located in North Dakota. More complicated are the headquarters functions, most of which are located in Bismarck but apply to all MDU states, some to both gas and electric, and at the top, to both regulated and unregulated activities.

Q. WHAT ARE THE COMPONENTS OF THE REVENUE REQUIREMENT?

A. The components are maintenance and operating expenses, including depreciation, income taxes, and a return on rate base. The term "return" is synonymous with "profit," but in utility regulation it is treated as a cost, specifically the cost of equity capital. That cost will be the subject of Part II of this testimony.

Q. WHAT TEST YEAR DOES THE COMPANY PROPOSE IN THIS CASE?

A. The Company proposes two test years, 2004 and 2005. Calendar year 2004 is the basis for MDU's "interim" relief, presumably to take effect as soon as the Commission reaches a decision in this case. Calendar year 2005 is proposed as the basis for MDU's "permanent" relief, with rates presumably taking effect on January 1, 2005.

Q. THESE ARE BOTH FORECAST YEARS. WHAT STANDARDS GOVERN THE USE OF FORECAST TEST YEARS?

A. In 1995, the North Dakota legislature enacted legislation that offered utilities a choice as to test years:[3]

> 1. A public utility, at its option, may use any one of the following twelve-month periods as its test year for rate filings with the commission:
>
> a. A historical test year, which may be either the latest twelve-month period for which actual data is available at the time of filing new schedules or the latest calendar or fiscal year for which actual data is available at the time of filing new schedules.
>
> b. A current test year, which is any consecutive twelve-month period ending not later than twelve months after the date new schedules are filed. A public utility selecting a current test year also shall file data for the twelve-month period immediately preceding the current test year selected and that period is the "historical period" for the public utility.
>
> c. A future test year, which is any consecutive twelve-month period ending no later than twenty-four months after the date new schedules are filed. A public utility selecting a future test year must file data for the twelve consecutive months immediately preceding the future test year and that period is the "current period" for the public utility.
>
> 2. A public utility selecting a current or future test year shall present the following information:
>
> a. A comparison of forecast data to historical period data to demonstrate the reliability and accuracy of the utility's forecast including a comparison of the prior years' forecast or budgeted data to actual data for those periods.
>
> b. A statement that the public utility's forecast is reasonable, reliable, and was made in good faith and that all basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the commission to test the appropriateness of the forecast.
>
> c. A statement that the accounting treatment that has been applied to anticipated events and transactions in the forecast is the same as the accounting treatment to be applied in recording the events once they have occurred.
>
> 3. The public utility may update its filing for material changes as actual data becomes available up to thirty days before the hearing. Except for good cause

[3] ¶49.05.04.1

shown, a public utility may not submit more than one updated filing before the hearing. In the absence of an updated filing by the public utility, the commission may require a public utility to update its filing when the commission staff introduces evidence that a material change has occurred.

4. A public utility may propose estimated or calculated adjustments to the selected historical or current test year for all known and measurable changes in operating results as measured in the test year. The adjustments must be made in the same context and format as the information was provided in the original filing. The adjustments may reflect material changes in plant investment, operating revenues, expenses, and capital structure if the changes occurred during the selected historical or current test year or are reasonably certain to occur subsequent to the selected test year within twelve months from the date of the rate filing.

Q. IS MDU'S SELECTION OF 2004 AND 2005 IN ACCORDANCE WITH PARAGRAPH 1c QUOTED ABOVE?

A. Yes. The latest test year, calendar year 2005, ends two months before the 24-month limit from the date the Company filed its application and schedules, March 3, 2004.

Q. HAS MDU SUBMITTED A COMPARISON OF FORECAST DATA TO HISTORICAL PERIOD DATA, AS REQUIRED BY PARAGRAPH 2a QUOTED ABOVE?

A. Yes. That information is provided in Statement N. Further detail, comparing 2003 actual expenses with budgeted 2004 expenses, is found in the Statement N workpapers.

Q. HAS MDU DEMONSTRATED THAT "ALL BASIC ASSUMPTIONS USED IN MAKING OR SUPPORTING THE FORECAST ARE REASONABLE, EVALUATED, IDENTIFIED AND JUSTIFIED TO ALLOW THE COMMISSION TO TEST THE APPROPRIATENESS OF THE FORECAST," AS REQUIRED BY PARAGRAPH 2b QUOTED ABOVE?

A. Not in every case, as I shall discuss subsequently in this testimony.

Q. ARE THE TEST YEAR ADJUSTMENTS "KNOWN AND MEASURABLE CHANGES" THAT "ARE REASONABLY CERTAIN TO OCCUR" AS REQUIRED BY PARAGRAPH 4 ABOVE?

A. Again, not in every case, as I shall discuss subsequently in this testimony.

Q. WHAT SPECIFIC ITEMS IN THE COMPANY'S FORECAST TEST YEAR RESULTS FAIL THE "REASONABLE, EVALUATED, IDENTIFIED AND JUSTIFIED", "KNOWN AND MEASURABLE" AND "REASONABLY CERTAIN TO OCCUR" TESTS SET FORTH IN THE LEGISLATION QUOTED ABOVE?

A. I have identified one revenue assumption, eight expense elements, and one rate base adjustment that fail these tests. They relate to the following items:

- The assumption that a one percent conservation adjustment applies to commercial and industrial customers;
- The inclusion of the Company's Supplemental Income Support Plan ("SISP") as an expense item;
- The inclusion of the cost of SISP-related testimony in the Company's rate case expenses and a three-year amortization of those expenses;
- The inclusion of bonuses related to Company profitability;
- The inclusion of institutional advertising a recoverable expense;
- The projection of vehicles and work equipment expense based on their depreciation charges;
- The projection of 2005 pension and post-employment benefit costs;
- The projection of miscellaneous costs into 2005;
- The incorporation of officers compensation increases since 1999; and
- The failure to reflect growth in contributions in aid of construction.

Q. HAVE YOU SUMMARIZED THE EFFECT OF THE ADJUSTMENTS YOU PROPOSE ON MDU'S CLAIMED 2004 AND 2005 REVENUE REQUIREMENT?

A. Yes. The effect of these adjustments is shown on page 1 of Exhibit CWK-1.

ADJUSTMENT 1 – CONSERVATION REDUCTION

Q. WHAT IS THE CONSERVATION ADJUSTMENT TO WHICH YOU REFER?

A. In projecting its revenues into late 2004 and 2005, MDU has reduced the forecast consumption of all firm service customers by one percent to recognize the effect of improved appliance efficiency and improved insulation. This adjustment begins in September 2004 and runs through 2005.

Q. HAS THE COMPANY SUPPORTED THIS ADJUSTMENT?

A. Yes, but only for residential customers. In response to my data requests, the Company has provided several studies that persuasively support the one percent conservation adjustment for residential gas users.[4] However, the Company has provided no support whatever for the proposition, implicit in its adjustment, that the same degree of conservation will apply to commercial and industrial customers. Since it is the Company's burden to justify its adjustments, I consider the one percent reduction in commercial and industrial consumption as unsupported. It should therefore be disallowed.

Q. WHAT IS THE EFFECT OF THIS ADJUSTMENT?

[4] MDU response to Staff Data Request No. 3, Question 15.

A. As shown on page 2 of Exhibit CWK-1, the effect of eliminating the assumed one percent conservation reduction in commercial and industrial consumption during the last four months of 2004 is to increase total revenue for the year by $491,558. Of this amount, $458,597 represents revenue from the purchased gas adjustment, which would be offset by a corresponding reduction in cost. The net effect is to increase the Company's revenues by $32,961.

The impact on 2005 revenues is much greater because the Company has applied the adjustment throughout the entire year. When this adjustment to commercial and industrial consumption is eliminated, total revenues increase by $5,344,356, of which $4,985,995 represents fuel costs, leaving a net increase in 2005 revenue of $358,361.

ADJUSTMENT 2 – SUPPLEMENTAL INCOME SECURITY PLAN

Q. WHAT IS THE SUPPLEMENTAL INCOME SECURITY PLAN?

A. MDU's Supplemental Income Security Plan ("SISP") is a supplemental pension benefit to 48 officers and senior managers of MDU Resources, Inc. It provides "income replacement" at retirement of up to 80 percent for lower income employees qualifying for the plan to 50 percent for the higher income levels. SISP supplements the retirement income that these employees receive from Social Security, 401k plans, and the "qualifying" pensions that are available to all 1,013 employees of MDU Resources.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO SISP?

A. I recommend that SISP expenses be disallowed. MDU did not seek recovery of SISP expenses until the 2001-2002 electric rate case, Case No. PU-399-01-186, even though the plan has been in effect since 1982. In that case Staff argued that SISP is a double pension for senior management staff and is unduly weighted in

favor of the highest income employees. The Commission agreed with Staff and excluded SISP from recoverable expenses. The Commission again excluded SISP in the 2002 gas rate case, Case No. PU-399-02-183. The issue arose yet again in the recent electric case PU-399-03-296, but the case was settled, so the matter was never decided.

Quite apart from Commission precedent, an additional reason for disallowing SISP costs relates to incentives. The Internal Revenue Service treats payments into special retirement plans such as SISP that apply only to highly-paid senior executive managers and directors, most of whom are probably also stockholders, as taxable income of the Company. If these costs were allowed to be deductible, the managers and directors would have an incentive to hide corporate income by paying benefits to themselves through these plans.[5]

The same principle applies to the establishment of the regulated revenue requirement. The personnel who recommend the level of benefits are the same personnel who receive them.[6] If those benefits (along with associated income taxes) are incorporated into the revenue requirement, then the incentive will be make them very, very generous. That generosity would be entirely at the expense of the ratepayers.

Q. HOW DO YOU RESPOND TO MR. CONLEY'S ASSERTION THAT SISP IS A CONVENTIONAL AND NECESSARY PART OF THE COMPENSATION PACKAGE TO KEY EMPLOYEES AND IS REQUIRED TO MAKE MDU COMPETITIVE WITH OTHER EMPLOYMENT OPPORUNITIES AVAILABLE TO THESE HIGHLY SKILLED INDIVIDUALS?

[5] It is my understanding that the IRS does allow deduction of pension payments to retired employees.
[6] Executive compensation is ultimately determined by a Compensation Committee consisting of three outside (non-employee) directors. However, this committee acts on the recommendations of management

A. Even if the managers and directors exert self-control and avoid overly generous benefits, the benefits should still be paid by shareholders. As Mr. Conley accurately points out, the employees who receive SISP "are responsible for planning for the future, identifying and implementing appropriate strategies for the Company, implementing effective cost reduction programs, streamlining the organization, implementing new technologies and maintaining and increasing the efficiencies of the Company." As such, they are the direct representatives of the Company's stockholders, and they are the employees most responsible for providing the profits that those stockholders expect. For this reason, I believe that the stockholders, not ratepayers, should bear the relatively minor cost of supplementing the retirement income of these key individuals.

Q. WHAT ARE THE COSTS OF SISP THAT YOU ARE RECOMMENDING BE DISALLOWED?

A. On Statement N, page 10, MDU reports that its 2004 SISP costs are expected to be $260,000 and its 2005 SISP costs are forecast as $243,000.

ADJUSTMENT 3 – RATE CASE EXPENSES

Q. WHAT RATE CASE EXPENSES DOES THE COMPANY PROPOSE TO INCLUDE IN ITS REVENUE REQUIREMENT?

A. The Company is seeking to incorporate $124,610 in rate case expenses into its revenue requirement for both 2004 and 2005. These include a three-year amortization of $244,557 in expenses for this case, $42,000 in amortization for the last gas case, No. PU-399-02-183, and $1,091 in recurring annual regulatory expenses.

supplemented by reports from outside compensation consultants such as The Hay Group and Towers Perrin.

Q. WHAT ADJUSTMENTS DO YOU PROPOSE IN THESE EXPENSES?

A. I propose two adjustments. The first is a follow-through from the last adjustment. If SISP costs are to be disallowed, then the cost of hiring the witness to support SISP's inclusion should likewise be disallowed. That amount is $79,400. Second, I propose that the remaining expenses from this rate case be amortized over four years, consistent with the amortization period of expenses from the last rate case.

Q. WHAT IS THE EFFECT OF THESE TWO ADJUSTMENTS ON THE ANNUAL RECOVERY OF RATE CASE EXPENSES?

A. As shown on page 3 of Exhibit CWK-1, I propose that rate case expenses be reduced from $124,610 to $84,380, or by $40,230.

ADJUSTMENT 4 – BONUSES

Q. WHAT BONUS AMOUNTS HAS MDU INCLUDED WITH ITS LABOR EXPENSES?

A. The Company has based its 2004 and 2005 North Dakota labor costs on the expected percentage changes in total Company-wide labor costs from the preceding year. In projecting its 2004 labor cost, however, the Company did not include its forecast 2004 bonuses, but instead a three-year average of bonuses during 2002 through 2004. This treatment appears to reduce 2004 gas service bonuses on a Company-wide basis from $2,839,960 to $1,875,113. It has the effect of reducing the 2003-2004 inflator for North Dakota labor costs from 7.77 percent to 6.82 percent.

Q. IS THERE ANY OBJECTION TO THIS PROCEDURE?

A. Yes. Bonuses are based in part on Company-wide profitability. I have no objection to flowing through to employees some of the benefits of improved profits when prices are stable. However, when profits increase due to rate cases, the incorporation into the subsequent rate case of bonuses resulting from those increased profits becomes circular. Rate case increases cause bonuses to increase, which then inflate the next rate case increase.

In this specific case, it would appear that one of the reasons that Company-wide gas service bonuses increased from $834,870 in 2002 to $1,950,510 in 2003 was the success of the Company in receiving, in December 2002, $1.972 million in additional revenue as a result of Case No. PU-399-02-183. One of the reasons that the Company expects its 2004 gas service bonuses to increase further to $2,839,960 may be the rate increase the Company hopes to obtain in this case.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO BONUSES?

I recommend that a portion of the increase in bonuses from their 2002 level to the three-year average used by the Company be disallowed. This portion would be the proportion of each bonus that is based on the profitability of the Company.

Q. WHAT SPECIFIC BONUS PLANS DOES THE COMPANY MAINTAIN?

A. The company has four separate bonus plans:

	2003 Amount[7]
• Executive Incentive Compensation Plan ("EICP")	$624,510
• Management Incentive Compensation Plan ("MICP")	165,539
• Mid–Management Plan	528,317
• BETA Plan	1,084,622
Total	$2,402,988

[7] Response to Staff Data Request No. 2, Question 13, Attachment B **Confidential**

Q. **TO WHAT EXTENT ARE THESE BONUS PLANS BASED ON THE PROFITABILITY OF THE COMPANY?**

A. The largest plan, and the clearest from the standpoint of identifying profit relationship, is the BETA plan. The maximum bonus is 7.0 percentage points of salary, and there are six measures comprising this total. The first measure is "utility earnings" which is up to 5 percentage points. The third measure is "group service and repair activities", which is up 0.5 percentage points. In spite of its name, this measure is profit–related because it depends specifically on district gross profits. Therefore, 5.5% of the 7.0% total (78.5 percent) is explicitly profit related.

Next clearest is the Mid–Management Bonus plan. The description furnished by the company states that "(t)he employee will receive 50% of the maximum payout based on achieving the corporate performance factor and will receive up to another 50% based upon achievement of individual goals."[8] Therefore, approximately 50 percent of this bonus is profit related. Indeed, the company's worksheet calls this component "utility profitability payout."

The other two plans, Executive Incentive Compensation Plan ("EICP") and Management Incentive Compensation Plan ("MICP"), are much more amorphous. Both plans are designed to reward successful corporate performance as measured against specified performance goals, as well as exceptional individual performance. Quoting from the EICP description, the primary basic concept is "(t)he performance measures used reflect both shareholder's interests (earnings) and customer interests (cost efficiency). In addition, individual performance will be evaluated and appropriate adjustments to target award levels may be made." [9] Nothing is actually specified or quantified in the Company's documentation we received. However, since these plans apply to senior executives, it would be

[8] Response to Staff Data Request No. 2, Question 13, Attachment A.
[9] Id.

very conservative to assume that 50 percent of the total is determined on the basis of profitability measures.

Q. HAVE YOU CALCULATED AN ADJUSTMENT THAT WOULD ELIMINATE THE PROFIT-RELATED PORTION OF THE INCREASES IN BONUSES?

A. Yes. Page 4 of Exhibit CWK-1 shows this calculation. The first five lines calculate the increases in bonuses from 2002 to the three-year average 2002-2004. That increase is $1.04 million for all gas operations. On lines 6 through 10, I calculate that 62.9 percent of this increase is related to the profitability of the Company. For total gas operations, the profit-related increase in bonuses is $653,937, or 2.68 percent of total labor costs. When applied to North Dakota, the disallowance or the profit-based bonus increase is $244,613 in 2004 and $257,670 in 2005.

ADJUSTMENT 5- INSTITUTIONAL ADVERTISING

Q. WHAT FORMS OF ADVERTISING DOES THE COMPANY PURCHASE?

A. There are three forms of advertising that the Company purchases, informational, promotional and institutional. In 2003, the Company paid $27,000 for informational advertising, $35,000 for promotional advertising, and $111,000 for institutional advertising, for a total of $173,000 in advertising expenses.

Q. HOW MUCH OF THIS ADVERTISING EXPENSE DOES THE COMPANY SEEK TO RECOVER FROM RATEPAYERS?

A. The Company seeks to recover $138,000 from ratepayers in both 2004 and 2005. This amount includes informational and institutional advertising, but no promotional advertising.

Q. HOW ARE "INFORMATIONAL" AND "INSTITUTIONAL" ADVERTISING DEFINED?

A. The Uniform System of Accounts of the Federal Energy Regulatory Commission ("FERC") defines informational advertising as follows:

> (A)ctivities which primarily convey information as to what the utility urges or suggests customers should do in utilizing gas service to protect health and safety, to encourage environmental protection, to utilize their gas equipment safely and economically, or to conserve natural gas.[10]

NDCC 69-09-01-29 states as follows:

> "Institutional advertising" means advertising which has as its primary objective the enhancement or preservation of the corporate image of the utility and to present it in a favorable light to the general public and investors.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THESE TWO FORMS OF ADVERTISING?

A. It is obvious that informational advertising benefits ratepayers because it conveys to them information they need for the safe and efficient use of their gas appliances. The same cannot be said of institutional advertising. As defined by the North Dakota code, it appears to accrue to the primary benefit of stockholders by persuading the public to take a more favorable view of the Company. It is also designed to influence investors favorably, with the immediate effect of increasing the share prices of the Company's stock. For this reason, I recommend that institutional advertising be supported by the Company's shareholders, not by its ratepayers.

Q. WHAT IS THE EFFECT OF THIS ADJUSTMENT ON THE COMPANY'S REVENUE REQUIREMENT?

A. The Company predicts that its institutional advertising budget will remain at its 2003 level through 2004 and 2005. That level is $111,000 per year. This amount should be removed from the Company's revenue requirement in each year.

ADJUSTMENT 6 – VEHICLES AND WORK EQUIPMENT

Q. HOW HAS THE COMPANY FORECAST THE OPERATING AND MAINTENANCE EXPENSE OF ITS VEHICLES AND WORK EQUIPMENT FOR THE YEARS 2004 AND 2005?

A. The Company has forecast its vehicles and work equipment expense based on the predicted depreciation charges for these categories of equipment from 2003 to 2004 and 2005.

Q. IS THIS A REASONABLE BASIS FOR FORECASTING OPERATING AND MAINTENANCE EXPENSES?

A. No. In a delayed phase of the last rate case, Case No. PU-399-02-183, MDU and the Staff agreed to a settlement that changed the Company's gas and common plant depreciation rates. Among the most radical changes were increases in the depreciation rates for vehicles. The settlement was approved on July 31, 2003 and the rates became effective September 1, 2003. This Commission-approved depreciation rate increase accounts for the dramatic increase in vehicle depreciation from $290,000 in 2003 to a projected $606,000 in 2004.[11]

[10] 18 CFR Ch 1, ¶ 909.
[11] See Statement N workpapers, page 67.

The change in depreciation expense might be an appropriate predictor of operating and maintenance expense if the depreciation rate remained the same, but there is no reason whatever to believe that O&M expenses would increase when the depreciation rate changes.

Q. WHAT IS THE APPROPRIATE BASIS FOR PREDICTING VEHICLE AND WORK EQUIPMENT O&M EXPENSES?

A. It is fairly obvious that gross plant would be a much better indicator of the requirements for operating and maintaining vehicles and work equipment.

Q. HAVE YOU CALCULATED THE ADJUSTMENT REQUIRED TO RESTATE 2004 AND 2005 VEHICLE AND WORK EQUIPMENT O&M EXPENSES ON THE BASIS OF GROWTH IN GROSS PLANT INVESTMENT?

A. Yes. That calculation is presented on page 5 of Exhibit CWK-1. It shows that if vehicle and work equipment O&M expenses are forecast on the basis of gross plant, the 2004 expenses are reduced by $265,000, and the 2005 expenses are reduced by $297,000.

ADJUSTMENT 7 – PENSION AND OPEBs

Q. WHAT COSTS HAS MDU INCLUDED IN ITS TEST YEAR REVENUE REQUIREMENTS FOR PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS?

A. The Company has included $295,000 for pensions and $619,000 for Other Post-Employment Benefits ("OPEBs") – principally health insurance – in its 2004 revenue requirement, for a total of $914,000. The Company predicts that in 2005

pension costs will almost double to $546,000, and OPEBs will increase to $635,000, for a total cost in that year of $1,181,000.[12]

Q. WHAT WERE THE COSTS FOR THESE ITEMS IN 2003?

A. In 2003, pension costs were negative 201,000, and OPEB costs were $579,000.

Q. WHAT ACCOUNTS FOR THE VERY DRAMATIC INCREASE IN PENSION COSTS?

A. Under Statement of Financial Accounting Standards No. 87, the annual recognition of pension costs is very much affected by the relationship of the asset value of the pension fund to the Projected Benefit Obligation ("PBO"). The PBO is based on an actuarial analysis of the cumulative future obligations to pay pensions to existing and retired employees. Those obligations are discounted to their present value based on the current yield of corporate bonds. When the asset value of the pension fund is greater than the PBO, then pension costs are negative, as happened in 2003. But when the PBO exceeds the asset value of the pension fund, then pension costs can become quite large.

Both the asset value of the pension fund and the PBO are somewhat unstable numbers. The value of the pension fund is heavily influenced by changes in the securities markets. If the stock market declines, the value of the pension fund declines, and a shortfall against the PBO develops. Also, if the current earnings of the fund decline, then there is less money to offset current pension payments, and again, the pension costs increase.

The PBO is also subject to change, principally due to changes in interest rates. Paradoxically, when interest rates decline, the PBO increases. That is because the factor used to discount the future obligations to their present value declines,

[12] Statement N, page 10.

increasing the PBO. Conversely, if interest rates increase, then the present value of the PBO declines, all else being equal.

Between 2003 and 2004, the asset value of MDU's pension funds declined due to the poor performance of the stock market. Meanwhile, interest rates fell to their lowest levels in decades, so that the present value of the PBO increased. The result was a PBO that exceeded the value of the pension fund, creating a sudden jump in pension costs.

Q. WHAT ACCOUNTS FOR THE DRAMATIC INCREASE IN PENSION COSTS IN 2005.

A. The Company has forecast both the asset value of its fund and its PBO. That forecast shows a much higher pension cost in 2005 than 2004.

Q. IS THIS FORECAST REASONABLE?

A. I do not see how it can be. To forecast 2005 pension costs requires the Company to predict measures that it cannot possible know. Specifically, the Company must predict the asset value of its pension fund, it must predict the earnings of the pension fund, and it must forecast the interest rate on corporate bonds, all as of the end of 2004. These values are not "known and measurable" as required by North Dakota law. That being the case, the Company's pension costs are not known and measurable.

Q. WHAT ADJUSTMENT DO YOU PROPOSE FOR PENSION COSTS?

A. I recommend using the latest "known and measurable" cost of pensions, which is the 2004 cost, calculated at the beginning of that year, as the costs for 2005.

Q. DO THE SAME CONSIDERATIONS APPLY TO OPEBs?

A. Yes. Statement of Financial Accounting Standards No. 106 ("SFAS 106"), which covers OPEBs, parallels SFAS 87, which covers pensions. The same problem with "known and measurable" costs applies to OPEB costs as well.

Q. WHAT IS THE EFFECT OF YOUR PROPOSED ADJUSTMENT TO PENSION AND OBEP COSTS?

A. As shown on page 6 of Exhibit CWK-1, the effect of holding 2005 pension and OPEB costs to their 2004 levels is to reduce the Company's 2005 revenue requirement by $267,000.

ADJUSTMENT 8 – 2.5 PERCENT INFLATION FACTOR

Q. WHAT IS THE 2.5 PERCENT INFLATION FACTOR?

A. In forecasting its 2005 expenses, MDU made specific predictions with respect to most of its costs. Labor, for example, was forecast based on the Company's union contract. Depreciation reflected its capital additions budget. But for the remainder of its expenses, it used a 2.5 percent inflation factor from the budgeted 2004 costs. The specific costs that were inflated by this factor were:

- Contract Labor,
- Materials, net of capital installation credits and reimbursements,
- Postage,
- Telephone,
- Office Supplies, and
- All other operating and maintenance costs.

Q. WHAT IS THE BASIS FOR THE 2.5 PERCENT FACTOR?

A. The 2.5 percent factor is intended to be the overall rate of inflation between the year 2004 and 2005. It is presumably based on 10 different forecasts of consumer price inflation that the Company presented on page 9 of its Statement N workpapers.

Q. DO THE 10 FORECASTS SUPPORT A 2.5 PERCENT INFLATION FACTOR BETWEEN 2004 AND 2005?

A. No. The average of the 10 forecasts for 2004 is 1.84 percent, and for 2005 it is 2.22 percent. The simple average of these two numbers is 2.03 percent.

Q. DOES THE USE OF A 2.5 PERCENT INFLATION FACTOR REFLECT "KNOWN AND MEASURABLE" CHANGES THAT ARE "REASONABLY CERTAIN TO OCCUR," AS REQUIRED BY NORTH DAKOTA LAW?

A. No. The Company has put forth no data to demonstrate that these various items of cost will change in lock step with changes in the Consumer Price Index. It is possible that some of these costs may, in fact, decline between 2004 and 2005. Postage, for example could decline if the Company uses more electronic billing. The increased use of e-mail could cause telephone costs to decrease. Contract labor appears to vary erratically. Page 12 of Statement N shows that two of the four categories of contract labor costs are budgeted to decline between 2003 and 2004.

Q. BUT DOESN'T IT STAND TO REASON THAT COSTS WILL INCREASE BETWEEN 2004 AND 2005?

A. No. Between November 1993 and December 2003, MDU's gas rates (exclusive of the cost of gas) did not increase. In fact, rates were reduced by $800,000 in

1999.[13] During that ten-year period, the CPI increased 26.4 percent.[14] Apparently, MDU was able during those years to hold its cost increases relative to its revenue growth well below the rate of inflation.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THESE COSTS?

A. Since the Company apparently has no specific bases for predicting the 2005 level of these various cost categories, I recommend that they be held to their budgeted 2004 levels for the year 2005.

Q. WHAT IS EFFECT OF THIS ADJUSTMENT?

A. Page 7 of Exhibit CWK-1 shows that the impact of holding these six categories of expense to their 2004 levels is to reduce the Company's 2005 revenue requirement by $85,000.

ADJUSTMENT 9 – OFFICERS' COMPENSATION INCREASES

Q. WHAT IS THE ISSUE WITH RESPECT TO OFFICERS' COMPENSATION?

A. The issue is presented on page 8 of Exhibit CWK-1. At the top of the page, I show the number of employees, the average annual compensation, and the average annual increase in per-employee direct compensation between 1999 and 2003 for each category of MDU's employees. The tabulation reveals that the Company's officers enjoyed average annual increases in compensation of 19.5 percent. The only other categories that even approached this level of increase were the next levels down, the regional managers and the directors, who received

[13] See Order Approving Settlement Offer, Case No. PU-399-96-325, December 16, 1998.
[14] All urban consumers, November 1993: 145.8; December 2003:184.3 bls.gov/pub/special requests/cpi

8.8 and 8.1 percent annual increases, respectively. All other categories received increases within the range of 2.6 to 6.2 percent annually.

In the middle of the page, I display the annual numbers for officers and all other employees for each year since 1999. This tabulation reveals that, in addition to receiving annual increases more than twice those of any other category of employees, the number of officers increased from 7 to 10, accounting for three of the four net employee increase between 1999 and 2003. Total officer compensation increased 30.2 percent annually as against 4.9 percent for all other employees. In 1999, officer compensation amounted to 3.4 percent of all other compensation. By 2003, that percentage had increased to 8.1 percent.

The issue is whether these highly disproportionate compensation increases should be passed through to ratepayers in the form of higher rates, or whether shareholders should be required to absorb some or all of these increases.

Q. DOES THIS ISSUE INVOLVE THE SAME CONSIDERATIONS AS THOSE RELATED TO THE SUPPLEMENTAL INCOME SECURITY PLAN (SISP)?

A. Yes, it does. These disproportionate compensation increases have been awarded solely to the handful of top management personnel. No other class of employees has enjoyed even half the rate of compensation increase. The determination of management compensation is made by a three-member compensation committee selected from the outside (non-employee) directors of the Company. Nevertheless, this compensation committee acts on the advice and recommendations of management, augmented by consultants' reports that may reflect a bias toward pleasing their clients. For this reason, it is not unfair to argue that the compensation awards to senior officers are influenced, if not directly determined by the recipient officers themselves. A check against the possibility

of such self-serving activity is to challenge the incorporation of the disproportionate compensation increases into the ratepayers' revenue requirement.

Additionally, as with SISP, the officers who receive these benefits are the direct representatives of the shareholders. They, more than any other employees, are beholden to the shareholders to maximize profits, build shareholder value, and ensure the integrity of the shareholders' equity investment. For this reason, it is not unreasonable to ask shareholders to support the portion of the officers' compensation increases that exceeds those of other employees of the Company.

Q. ARE THERE ANY OTHER CONSIDERATIONS THAT BEAR DIRECTLY ON THE OFFICER' COMPENSATION INCREASES?

A. Yes. The request to incorporate these disproportionate officer compensation increases comes in the context of two rate increase applications in as many years. To some extent, these applications reflect a failure of management. Between 1993 and 2001, MDU was able to resist seeking rate increases without suffering any significant loss in net income. Indeed, the Company agreed to reduce rates in 1998. Then, in 2002, the Company approached this Commission for a rate increase. This was the same year that the Company's officers enjoyed an 11.2 percent increase in direct compensation, and the number of officers increased from seven in 2000 to nine in 2002. Following the end of 2003, the Company again approached the Commission for a rate increase. This filing followed a year during which average officer compensation vaulted 25.2 percent, and the number of officers increased again, now to 10. To my knowledge, this increase in the number of officers has not coincided with any expansion in the scope of activities conducted by the Company.

It seems highly inappropriate to impose rate increases on ratepayers that reflect disproportionate compensation increases to the very employees who were positioned to avoid those rate increases. One might even argue that those

employees should be penalized, not rewarded, for the fact that now, after almost a decade of rate stability, they suddenly find that they cannot maintain the profitability of the operation without two rate increases in two years.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND WITH REGARD TO OFFICERS' COMPENSATION?

A. I recommend that the base year 2003 revenue requirement be reduced by the extent to which increases in officers' compensation since 1999 have exceeded increases in compensation to all other employees.

The calculation of the adjustment is presented at the bottom of page 8 of Exhibit CWK-1. Non-officer compensation has increased at an annual rate of 4.9 percent since 1999. Had officers' compensation increased at that rate, it would have been $2,210,750 less in 2003 than it actually was. To identify the portion of this disproportionate increase allocable to North Dakota gas operations, I used the ratio of total company SISP costs to North Dakota gas SISP costs, as claimed by the Company. That proportion is 13.125 percent, so that the recommend disallowance is $290,154. This disallowance applies to both test years, 2004 and 2005.

ADJUSTMENT 10 – CUSTOMER ADVANCES FOR CONSTRUCTION

Q. WHAT ARE CUSTOMER ADVANCES FOR CONSTRUCTION?

A. These are advances that customers make to cover their allotted portion of new construction when the Company extends (or expands) gas lines to service specific customers or, in the case of developers, new neighborhoods. These advances are an offset to capital costs included in rate base.

Q. WHAT ASSUMPTION HAS THE COMPANY MADE WITH RESPECT TO THE TEST YEAR AMOUNTS OF THESE ADVANCES?

A. As shown on page 12 of Statement N, the Company has assumed that customer advances during 2004 and 2005 will remain at their 2003 average level.

Q. IS THIS A REASONABLE ASSUMPTION?

A. No. A much more reasonable assumption would be that customer advances would change as the level of construction changes. Since the Company is assuming that its construction budget will increase, it should as well assume that customer advances will increase.

Q. WHAT IS THE EFFECT OF MATCHING THE RATE OF CUSTOMER ADVANCES TO THE RATE OF CONSTRUCTION DURING THE YEARS 2004 AND 2005?

A. Page 9 of Exhibit CWK-1 shows that MDU has forecast increases in capital additions of 20.2 percent in 2004 over 2003 and 8.8 percent in 2005 over 2004. Applying these percentage increases to customer advances has the effect of reducing rate base by $51,000 in 2004 and by $78,000 in 2005. The corresponding reduction in depreciation during 2004 is $2000 and in 2005 it is $3000.

SUMMARY OF ADJUSTMENTS

Q. WHAT IS THE OVERALL EFFECT OF ALL OF THE REVENUE, EXPENSE AND RATE BASE ADJUSTMENTS YOU HAVE RECOMMENDED?

A. Page 1 of Exhibit CWK-1 shows that the cumulative effect of the adjustments I have made is to increase the Company's net operating income from North Dakota gas distribution operations during 2004 from $672,000 to $1,497,000 and from $51,000 to $1,287,000 in 2005. These figures reflect the calculation of income taxes on page 10 of Exhibit CWK-1. The after-tax rate of return in 2004 is 7.440 percent in 2004, rather than 3.332 percent. In 2005, the rate of return is 6.177 percent, rather than the Company's asserted 0.244 percent.

PART II – RATE OF RETURN

Q. WHAT HAVE YOU FOUND TO BE THE APPROPRIATE RATE OF RETURN ON MSU'S NORTH DAKOTA GAS RATE BASE?

A. Based on the analyses presented in this testimony, I find that the appropriate rate of return on the Company's gas rate base in North Dakota is **7.926 percent,** inclusive of a return to equity of **9.0 percent.** These percentages are presented in Exhibit CWK-2.

Q. WHAT INFORMATION DID YOU EXAMINE IN PREPARING YOUR TESTIMONY ON RATE OF RETURN?

A. I began by reading the testimonies of MDU witnesses Craig Keller and J. Stephen Gaske and their associated exhibits and statements. I prepared a series of data requests to which the Company responded. These responses in turn prompted a further round of data requests to which the Company has since responded. I also reviewed the rate of return portion of the Commission's December 10, 2002 decision in Case No. PU-399-02-183, MDU's last gas case, which as I shall discuss, is the basis for my recommendation in this case.

Q. WHAT COMPONENTS MAKE UP MDU'S RATE OF RETURN?

A. There are three components to MDU's rate of return, the capital structure, the cost of preferred stock and debt, and the cost of equity.

Q. WHAT CAPITAL STRUCTURE DOES THE COMPANY PROPOSE?

A. The Company proposes a forecast capital structure for the year 2005, as follows:[15]

Long Term Debt	$153,350,000	43.535%
Preferred Stock	16,050,000	4.614%
Common Equity	182,743,012	51.908%
Total	$352,243,012	100.000%

Q. IS THIS AN APPROPRIATE CAPITAL STRUCTURE?

A. No. In its order in the last gas rate case, Case No. PU-399-02-183, the Commission agreed with me that the capital structure should reflect the makeup of the rate base. The rate base includes elements such as materials and supplies inventories, fuel stocks and prepayments, which are short-term commitments that would be financed with short-term debt. Accordingly, the Commission included short-term debt in MDU's capital structure.

Q. HOW HAVE YOU CALCULATED SHORT-TERM DEBT FOR PURPOSES OF INCORPORATING IT INTO MDU'S CAPITAL STRUCTURE?

A. MDU uses a forecast 2005 capital structure, which it is entitled to do under North Dakota law. Since short-term debt is quite variable, it is difficult to predict with any precision. For this reason, I have used the average amount of short-term debt outstanding during the four most recent quarters for which data are available. As

[15] MDU Statement F, page 3.

shown in Note 3 on Exhibit CWK-2, the average daily amount of short-term debt outstanding during the four quarters ending March 31, 2004 was $34.67 million, and the average annualized cost was 1.18 percent.

Q. WHAT IS THE CAPITAL STRUCTURE THAT INCLUDES THIS ESTIMATE OF SHORT-TERM DEBT?

A. That capital structure is developed in Exhibit CWK-2. It consists of the following components:

Long Term Debt	$153,350,000	39.634%
Short Term Debt	34,670,505	8.961%
Preferred Stock	16,250,000	4.614%
Common Equity	182,843,012	47.257%
Total	$386,913,517	100.000%

Q. WHAT DO YOU RECOMMEND AS THE COST OF DEBT AND PREFERRED STOCK?

A. I have accepted the Company's estimate that its 2005 cost of debt will be 8.518 percent and its cost of preferred stock will be 4.614 percent.

Q. WHAT RETURN TO EQUITY DO YOU RECOMMEND?

A. I recommend a return to equity of 9.0 percent.

Q. HOW DID YOU ARRIVE AT THIS FIGURE OF 9.0 PERCENT?

A. I have simply implemented all of the Commission's findings with respect to equity return in its December 10, 2002 decision in Case No. PU-399-183. In that case, I disputed the Company's witness, Stephen Gaske, on a number of topics.

On some, the Commission sided with me, on others with Dr. Gaske, and on still others, it acknowledged both our arguments but declined to adjust the rate of return based on them. A summary of the Commission's findings is as follows:

- The Commission agreed with me that Dr. Gaske's flotation cost adder should be rejected.
- The Commission agreed with my broader selection of comparison gas distribution companies.
- The Commission adopted Dr. Gaske's factor of 1.625 for calculating next year's dividends.
- The Commission adopted the more current data that I presented.
- The Commission found the "basic DCF" calculation most useful and rejected the modifications of it recommended by both Dr. Gaske and myself.
- The Commission declined to adjust the basic DCF findings for the risk considerations recommended by both Dr. Gaske and myself.
- The Commission declined to adjust the basic DCF findings based on "benchmark" analyses recommended by both Dr. Gaske and myself.

Q. DOES DR. GASKE'S PRESENTATION IN THIS CASE REFLECT THE COMMISSION'S FINDINGS IN CASE NO. PU-399-02-183?

A. Only in one respect. Dr. Gaske has expanded his selection of comparison companies from six to ten. Otherwise, Dr. Gaske repeats virtually all of the arguments and makes the same adjustments that he made in the last case.

Q. WHAT IS THE RESULT OF DR. GASKE'S ANALYSES IF YOU ADOPT ALL OF THE FINDINGS THAT THE COMMISSION MADE IN THE LAST CASE?

A. Exhibit CWK-3 replicates the table on page 19 (para. 79) in the Commission's order in Case No. PU-399-02-183. It was from that table that the Commission found MDU's rate of return. All of the data are drawn from Dr. Gaske's Exhibit

(SJG-2). Page 1 of Exhibit CWK-3 shows the results of the "basic" DCF analysis. Page 2 uses Dr. Gaske's "second-stage retention growth rate estimates" in which he weighted the growth factor two-thirds based on analysts' predictions and one third on a calculation of the ability of the utilities' to fund earnings growth given their pattern of reinvestment. The exhibit reveals that the basic DCF procedure yields a return of 9.96 percent, while the second-stage retention growth method shows a DCF return of 10.06 percent.

Q. HAVE YOU UPDATED THE DATA THAT YOU EXTRACTED FROM DR. GASKE'S EXHIBIT?

A. Yes. That updating is presented in Exhibit CWK-4. Page 1 of this exhibit reveals that an updating of Dr. Gaske's "basic" DCF analysis yields an average rate of return of 8.67 percent. On page 2 of Exhibit CWK-4, I have updated Dr. Gaske's "Second-stage Projected Earnings Retention Growth Rates" which are weighted one third by the retention growth potential and two-thirds by Zack's forecasts. The result of this calculation is a growth factor of 5 percent. Page 3 of Exhibit CWK-4 shows that this formulation of the DCF procedure yields a return of 8.93 percent.

Q. BASED ON THESE EXHIBITS, WHAT RETURN TO EQUITY DO YOU RECOMMEND?

A. Based purely on the results presented in Exhibit CWK-4, I could recommend a return to equity of 8.8 percent. However, this simple average contrasts strongly with the 10.0 percent that results from simply plugging Dr. Gaske's six-month old numbers into the calculation. It is also dramatically below the 11.329 percent found by the Commission in Case No. PU-399-02-183, decided December 10, 2002. For this reason, I recommend that the Exhibit CWK-4 results be rounded upward to **9.0 percent**.

Q. WHAT OVERALL RATE OF RETURN ON RATE BASE DO YOU RECOMMEND?

A. I recommend an overall post-tax rate of return on rate base of 7.926 percent. The calculation of this number is presented on Exhibit CWK-2.

Q. BASED ON YOUR RECOMMENDED RATE OF RETURN AND RATEMAKING ADJUSTMENTS, WHAT LEVEL OF RATE RELIEF DOES THE COMPANY REQUIRE?

A. My calculation of the revenue relief required by the Company is presented in Exhibit CWK-5. As calculated on page 1 of Exhibit CWK-1, the Company will earn an adjusted rate of return of 7.440 percent in 2004. It will require a revenue increase of $162,000 to bring this return up to the target of 7.926 percent in that year. In 2005, the Company will earn 6.177 percent on its adjusted rate base, and a revenue increase of $603,000 will be required to bring that return up to 7.926 percent.

PART III – COST ALLOCATION AND RATE DESIGN

Q. WHAT IS MEANT BY "COST ALLOCATION AND RATE DESIGN?"

A. Cost allocation conventionally refers to the process of distributing the revenue requirement among the respective classes of customers. In MDU's case, there are five classes of customers:

- Residential
- Firm General (non-residential)
- Air Force
- Small Interruptible
- Large Interruptible

These customer classes are not altogether mutually exclusive. Specifically, a number of the firm service customers have portions of their load on the interruptible rate schedules. For purposes of cost allocation, however, the firm and interruptible loads are considered to be in separate classes.

Rate design refers to the actual rates by which MDU collects its revenue. Gas service rate design is quite simple. There are only three rates:

- a Basic Delivery Charge per customer per day or per month,
- a Distribution Delivery Charge per dekatherm,
- a Cost of Gas Charge per dekatherm.

The first rate, the Basic Delivery Charge, is fixed for each class of customers. The Distribution Delivery Charge is fixed for firm service customers, including residential, but may be negotiated within maximums and minimums for interruptible customers. The Cost of Gas Charge changes quarterly based on the market price for gas and the pipeline charges for transportation and storage of gas.

Q. HAS MDU PERFORMED A COST ALLOCATION STUDY?

A. Yes. MDU's cost allocation study is Statement M in the Company's filing. It is sponsored by MDU witness Tamie Aberle. Ms. Aberle distributed the Company's 2005 expenses and rate base among the five classes. She then identified the revenue that each class would generate under present rates in 2005. From these data, she developed class rates of return, as follows:[16]

Residential Service	(3.26%)
Firm General Service	2.69%
Air Force	27.12%
Small Interruptible	18.91%
Large Interruptible	39.26%
Total Jurisdictional	0.243%

[16] Testimony of Tamie A. Aberle, page 4.

Q. DO YOU AGREE WITH MS. ABERLE'S STUDY?

A. No. I disagree with Ms. Aberle's allocation of the cost of distribution mains. Mains account for 36 percent of all North Dakota jurisdictional gas plant in service. The allocation of mains cost also "drives" the allocation of a number of other overhead costs. An inappropriate allocation of mains therefore results in a severely flawed cost allocation study.

Q. HOW DID MS. ABERLE ALLOCATE THE COST OF DISTRIBUTION MAINS?

A. Ms. Aberle has apparently assumed that one third of mains costs are "fixed", that is, not associated with the volume of gas that flows through the mains. She has allocated this one third based on the number of customers in the respective classes. She has allocated the remaining two-thirds "variable" mains costs on the basis of the respective classes' peak day consumption at the distribution level.

Q. WITH WHAT PORTIONS OF THIS ALLOCATION DO YOU DISAGREE?

A. I disagree with Ms. Aberle's one-third/two-thirds allocation between base and variable costs, and I disagree with her allocation of fixed costs on the basis of the number of customers.

Q. WHY DO YOU DISAGREE WITH MS. ABERLE'S ONE-THIRD/TWO-THIRDS BASE/VARIABLE ALLOCATION?

A. In response to a data request, the Company identified the total number of feet of plastic and metallic pipe of various diameters that it has installed over the last five years and the fully-loaded cost of that pipe and its installation. From these data, I

was able to identify the per-foot cost of installing pipe of various diameters, and therefore of various throughput capacities.

I then conducted regression studies of plastic and metallic pipe, using capacity (area within the pipe) as the independent variable, and cost per foot as the dependent variable. Because of the variation in the amount of steel pipe of varying diameters, I was not able to derive useful results from my metallic pipe regression. However, for the plastic pipe – which constitutes the majority of pipe installed – I was able to derive useful results. They are reported in Exhibit CWK-6. That exhibit demonstrates that the installation cost of plastic pipe is 30 percent variable and 70 percent fixed.

Q. WHY DO YOU OBJECT TO THE ALLOCATION OF FIXED MAINS COSTS ON THE BASIS OF THE NUMBER OF CUSTOMERS?

A. The difficulty with allocating fixed costs is that their very "fixedness" means that it is impossible to identify causality. The fixed costs of mains do not vary according to the amount of gas that passes through them. That being the case, Ms. Aberle has assumed that they must vary with the number of customers served. The problem with that argument is that, except for extensions on the very edge of the system, fixed mains costs do not vary by the number of customers either. A 100-yard section of 4.5 inch main will cost the same whether there are 1, 10, 100 or 1000 customers attached to it. The fixed costs of the main will not increase if customers are added, nor will they decrease if customers drop off.

Why were the mains constructed in the first place? Was it to reach customers, or was it to deliver gas? The answer is that it was to reach customers so that gas could be sold to those customers. The element of value is not the customer, but the gas that can be sold to the customer. To the extent there is causality to fixed mains costs, it is associated with this element of value, that is, gas delivered. For this reason, I have allocated fixed mains costs among the customer classes on the

basis of gas consumed. Other costs that are clearly related to the number of customers, e.g. services, meters, billing and collecting, continue to be allocated on that basis.

Q. HAVE YOU PERFORMED A REVISED COST OF SERVICE STUDY THAT INCORPORATES YOU PROPOSED CHANGES TO THE MAINS ALLOCATION?

A. Yes. Exhibit CWK-7 is a summary of the Company's cost of service study (Statement M) with the following changes to the allocation of mains investment:

- 30% allocated on the basis peak day demand at distribution level;
- 70% allocated on the basis of dekatherm throughput at distribution.

Q. WHAT ARE THE RESULTS OF YOUR REVISED COST OF SERVICE STUDY?

A. Exhibit CWK-7 reveals the following class rates of return. For purposes of comparison, I show the corresponding results from the Company's cost of service study:

	Staff Study	Company Study
Residential Service	-0.75%	-3.26%
Firm General Service	0.63%	2.69%
Air Force	12.78%	27.12%
Small Interruptible	1.56%	18.91%
Large Interruptible	5.68%	39.26%
Total Jurisdictional	0.243%	0.243%

The principal effect of my revision to the Company's study is to reduce the disparity in rates of return among the customer classes. However, the relative profitability among the classes remains much the same. Residential service continues to show the lowest rate of return. The negative numbers for this class

should be disregarded, however, as this study reflects 2005 costs that are overstated for reasons discussed earlier in this testimony. Firm general service generates the next higher return, although the disparity relative to residential service has now much reduced. The Air Force rates continue to generate the largest return, but again, the disparity relative to other classes is much reduced. The same can be said of the higher rates of return for the two interruptible classes.

Q. HOW, IF AT ALL, DO THESE REVISED RESULTS AFFECT THE DISTRIBUTION OF ANY REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. As noted, the Company's proposal is to increase the residential rates by the largest percentage, firm general service rates by a somewhat smaller percentage, and to hold the Air Force and interruptible service rates at their present levels. My study reduces the apparent need for these disparate class treatments, but it does not eliminate them. For this reason, I believe that the general format of the Company's revenue increase distribution should be maintained. Obviously, the amount of the increases will differ, since I find that the Company needs much less new revenue than it claims.

Q. WHAT SPECIFIC CHANGES IN RATES DOES THE COMPANY PROPOSE?

A. Concentrating solely on the final 2005 rates, the Company is proposing the following rate changes:

Rate Schedule	Basic Service Charge (per day)			Distribution Delivery (per dk.)		
	Pres.	Prop.	% Inc.	Pres.	Prop.	% Inc.
Residential Rate 60	$0.29	$0.30	3.4%	$0.641	$0.894	39.5%
General Svs. Rate 70 <500 cf. mtr	$0.50	$0.52	4.0%	$0.473	$0.626	32.3%
General Svs. Rate 70 >500 cf mtr.	$1.70	$1.75	2.9%	$0.473	$0.626	32.3%

The Company proposes modest increases in the Basic Service Charges. The bulk of its increases are collected through the Distribution Delivery Charges.

Q. DO YOU AGREE WITH THIS METHOD OF RECOVERING REVENUE?

A. If the Company were to receive all the revenue it is requesting, I would object to the recovery of most of it through the Distribution Delivery Charges. Being based on consumption, those charges are most susceptible to the effect of weather, and they come on top of what will probably be very large increases in the cost of gas this coming winter. Were the Company to receive its full revenue award, I would recommend that the increases be spread proportionally between the Basic Service Charge and the Distribution Delivery Charge.

However, I am proposing much more modest increases than the Company is seeking. Furthermore, I am also proposing a concurrent Distribution Delivery Stabilization Mechanism ("DDSM") that will have the effect of stabilizing the bill impact of the Distribution Delivery Charge in the face of unusually warm or unusually cold winters. If the Commission adopts my DDSM recommendation, then I would support an approach that adopts the Company's proposed small increases in the Basic Service Charge, and then recovers whatever further revenue that is required through the Distribution Delivery Charge.

Q. WHAT IS THE DDSM?

A. The DDSM – Distribution Delivery Stabilization Mechanism – is designed to adjust rates each year to correct for the under or over- collection of the distribution delivery charge during the previous heating season. The Company will calculate the extent to which revenue collections from each rate schedule departed from normal during each heating season, and it will surcharge or surcredit the Distribution Delivery Charge in each monthly bill beginning May 1 and the following 12 months.

Q. WHAT IS THE LOGIC BEHIND THE DDSM?

A. The theory underlying the DDSM is that the Company will be protected from the adverse effects of unusually warm winters by allowing it to recover the under-collections that result from relatively low gas sales. When there is unusually cold weather, the DDSM will reduce the appearance of excessive profitability that can result in pressure for rate reductions when, under normal weather conditions, no reductions are justified.

Q. WILL THE DDSM, AS PROPOSED BY THE COMPANY, ACHIEVE THESE BENEFITS?

A. No. To the contrary, the DDSM proposed by MDU could seriously aggravate the instability of revenue collection from year to year. That is because the one-year lag between heating seasons imposes the weather effects of the prior year on ratepayers without regard to the weather conditions during the current year. Assume that there is an unusually warm winter. As recommended by the Company, a DDSM surcharge would be imposed on all firm service customers beginning in May and running through to the following April. If the next heating season were unusually cold, then the Company would not only over-collect for the current cold season, it would compound that over-collection by recovering more than it intended from the prior warm winter.

The same thing would happen in reverse if a cold winter is followed by a warm one. The surcredit from the prior year would reduce the Company's revenue recovery, which would further be reduced by the unusually low dekatherm sales during the subsequent mild winter.

The exaggerated instability in revenue recovery would be passed through to customers. Whenever there are two consecutive winters with widely varying

average temperatures, ratepayers would experience changes in their bills that would be more exaggerated up or down than if there were no DDSM.

Q. CAN THIS DEFECT OF THE DDSM BE RECTIFIED?

A. Yes. If the DDSM operates concurrently with the variations in weather, then it will avoid exaggerating the effects of unusual weather. Instead, it will stabilize rates and revenues so as to cushion the effect of very cold or very mild winters on both customers and the Company.

Q. CAN THE DDSM BE MADE TO OPERATE ON A CONCURRENT BASIS?

A. Yes. The Company has indicated that the DDSM could be administered on a real-time basis so that the adjustment applies to the current billing period.[17]

Q. CAN YOU PROVIDE A RECOMMENDED TARIFF FOR A REAL-TIME DDSM?

A. Yes. Exhibit CWK-8 is copied largely word-for-word from the tariff of the Delta Natural Gas Company, a small gas distribution company operating in the Commonwealth of Kentucky. This provision, called the "Weather Normalization Adjustment" has been in effect since January 1, 2000. It differs from MDU's proposal in that it operates concurrently with the current billing cycle. It increases or decreases the per-dekatherm Distribution Delivery Charge in the customer's bill based on a factor representing the departure of the customer class's actual heat load from its normal heat load.

Q. ASIDE FROM STABILIZING CUSTOMERS' BILLS AND THE COMPANY'S REVENUES, HAS THERE BEEN ANY OTHER BENEFIT

[17] MDU Response to Data Request No. 1, Question 70.

FROM THE WEATHER NORMALIZATION ADJUSTMENT TO DELTA NATURAL GAS?

A. Yes. Virtually every investment analyst that has examined Delta Natural Gas has cited the Weather Normalization Adjustment as a factor reducing the risk of the Company's stock. There is little question that the Adjustment has resulted in a lower cost of capital for this company. There is every reason to believe that it would have the same effect on MDU.

Q. DO YOU THEREFORE RECOMMEND ADOPTION OF EXHIBIT CWK-8 AS PART OF MDU'S NORTH DAKOTA TARIFF?

A. Yes. I do.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes. It does.