

**MONTANA-DAKOTA UTILITIES CO.
CASE NO. PU-399-04-____
TESTIMONY AND EXHIBITS**

**In the Matter of the Application of
Montana-Dakota Utilities Co. for
Authority to Establish Increased Rates
For Natural Gas Service in the
State of North Dakota**

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-04-___

Direct Testimony
of
Bruce T. Imsdahl

1 Q. Please state your name and business address.

2 A. My name is Bruce T. Imsdahl and my business address is 400
3 North Fourth Street, Bismarck, North Dakota 58501.

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

5 A. I am the President of Montana-Dakota Utilities Co. (Montana-
6 Dakota), a Division of MDU Resources Group, Inc.

7 Q. Please describe your duties and responsibilities with Montana-Dakota.

8 A. I have executive responsibility for the development, coordination,
9 and implementation of Company strategies and policies relative to all
10 areas of operations.

11 Q. Please outline your educational and professional background.

12 A. In 1970, I received a Bachelor of Science degree in Mechanical
13 Engineering from North Dakota State University, Fargo, North Dakota. I
14 was granted certificates of attainment from the Joseph M. Kraatz Graduate
15 School of Business in Management Program for Executives from the
16 University of Pittsburgh, Pittsburgh, Pennsylvania in 1990 and from the

1 Graduate School of Business, Stanford University in the Executive
2 Management Program in 2003.

3 Upon graduating from college in 1970, I began my career with
4 Montana-Dakota as a results engineer at the Lewis & Clark electric
5 generating station. In 1973, I took an engineering position at the
6 corporate office and was responsible for the engineering at five of our
7 electric generating stations. In 1979, I transferred to the Lewis & Clark
8 Station as the Plant Superintendent, where I was responsible for all
9 engineering, operations, and maintenance of the plant. In 1983, I
10 transferred to the R. M. Heskett Station as the Plant Manager, where I
11 was again responsible for all engineering, operations and maintenance of
12 the plant. In 1985, I transferred to the corporate office as Generation
13 Manager, where I became responsible for all the electric generating plants
14 that Montana-Dakota owned and operated and the company's
15 Environmental Department. In 1989, I became Vice President - Power
16 Supply and, in November 1992, I was named Vice President - Energy
17 Supply assuming responsibility for natural gas supply as well as the
18 electric power supply. In February 2003, I was named Executive Vice
19 President. I became President of Montana-Dakota in July 2003.

20 I am a Registered Professional Engineer in North Dakota and
21 Montana. I also have been involved with the activities of the Electric
22 Power Research Institute, the Edison Electric Institute, the University of

1 North Dakota Energy & Environmental Research Center, and the
2 American Gas Association.

3 Q. What is the purpose of your testimony?

4 A. The purpose of my testimony is to provide an overview of our North
5 Dakota natural gas operations, explain our request for a gas rate increase
6 and discuss the policies and reasons underlying the major aspects of the
7 request. I will also identify the Company witnesses in this proceeding.

8 Q. Would you provide a summary of Montana-Dakota's gas operations in
9 North Dakota?

10 A. The North Dakota natural gas distribution system serves
11 approximately 85,600 customers in 76 communities. The customer mix is
12 about 86.6% residential, 13.2% firm commercial, with the small
13 interruptible and large interruptible customers making up about 0.2% of
14 customers. In addition, gas is provided to the U.S. Air Force base at Minot
15 and at a location in northeastern North Dakota. The residential, firm
16 commercial and small interruptible customers use natural gas primarily for
17 space and water heating. As such, Montana-Dakota's system has a low
18 load factor with peak gas requirements occurring during the winter with
19 summer loads being small by comparison. The total annual gas used by
20 our North Dakota customers is 18.3 Mmdk as projected for 2005 in this
21 case. Consumption by customer class is as follows: 45% residential,
22 31% firm commercial, 7% small interruptible, 12% large interruptible and
23 5% U.S. Air Force. Montana-Dakota's North Dakota gas service area is

1 divided into two operating regions with regional offices located in Bismarck
2 and Dickinson. In addition, there are a number of district offices located in
3 communities throughout the state. As of December 31, 2003, the
4 Company had 614 full and part time employees who live and work
5 throughout our North Dakota electric and gas service area.

6 Q. Mr. Imsdahl, did you authorize the filing of the rate application in this
7 proceeding?

8 A. Yes, I did.

9 Q. Why has Montana-Dakota filed this application for a gas rate increase?

10 A. Montana-Dakota is requesting an increase in its general gas rates
11 at this time because the current cost of providing natural gas service to
12 our North Dakota customers is not adequately reflected in the currently
13 authorized rates. It should be noted that this application does not include
14 any cost changes related to the cost of gas which is handled through the
15 Commission authorized Purchased Gas Cost Adjustment tariff.

16 Q. Would you please explain the basic elements that make up the total costs
17 of providing gas service, and which of those elements is subject to
18 regulation by this Commission?

19 A. Yes. The costs of providing natural gas service can be best broken
20 down into two major categories; first, the cost of gas delivered to the town
21 border station, where it leaves the interstate or intrastate pipeline and
22 enters our distribution system, and second, the cost of delivering the gas
23 from the town border station through our distribution system to the

1 individual customers. We call this portion distribution costs or non-gas
2 costs.

3 Natural gas purchased from a producer or supplier is a commodity
4 like wheat or corn and prices are not regulated. The charges for moving
5 the gas to our distribution system on the pipeline system are regulated by
6 the Federal Energy Regulatory Commission or other regulatory agencies.
7 These two elements, which we call "gas costs", are passed on to our
8 customers on a dollar-for-dollar basis as specified in the Purchased Gas
9 Cost Adjustment tariff, and there is no profit made by Montana-Dakota.
10 This portion comprises about 79% of a typical residential bill for gas
11 service.

12 The distribution cost portion of our rates is regulated by this
13 Commission and is the subject of this proceeding. This portion includes
14 operation and maintenance expenses, depreciation, taxes, and a
15 component for the opportunity to earn a return on the investment we have
16 in facilities to provide natural gas service. The distribution costs are about
17 21% of a typical residential bill.

18 Q. What is the amount of the increase requested?

19 A. As will be fully explained by other Company witnesses, the
20 Company is requesting an increase of \$3,334,226 based on a projected
21 2005 test year.

22 Q. How will the requested increase affect the various classes of customers?

1 A. The proposed percentage change in rates by customer class is as
2 follows:

3	<u>Class</u>	<u>Change</u>
4	Residential	3.5%
5	Firm General Service	2.3%
6	Air Force	0.0%
7	Small Interruptible	0.0%
8	Large Interruptible	0.0%
9	Total	2.8%

10 Q. What are the primary reasons that Montana-Dakota needs an increase at
11 this time?

12 A. The primary reason is increased operating expenses driven largely
13 by increases in labor and benefit costs.

14 Q. When was the last gas general rate increase for Montana-Dakota?

15 A. Montana-Dakota's gas rates were last increased in December
16 2002. The increase was \$1,972,000 annually and was authorized in Case
17 No. PU-399-02-183. I should also note that Montana-Dakota's gas rates
18 were decreased by \$362,000 on September 1, 2003 to reflect the
19 Commission approved settlement of depreciation expense in that same
20 case.

21 Q. Would you please explain why labor and benefit costs have increased
22 since the last rate case?

1 A. Yes. Montana-Dakota strives to pay its employees wages reflective
2 of the mid-range of the labor market. For union personnel, a new labor
3 contract was effective May 1, 2003. It was apparent during our
4 negotiation preparation that Montana-Dakota's wage levels were
5 substantially lower than the wage levels of our competitors and that they
6 had been lower for some time. The new union labor agreement, which
7 runs through April 30, 2007, reflects annual pay increases through May 1,
8 2006 for union employees to bring our wage levels more in line with the
9 wage levels of other companies we compete with for employees. With
10 respect to non-union personnel, Montana-Dakota retained a consulting
11 firm, the Hay Group, to lead a study of pay rates for all non-union jobs.
12 The results of that study clearly indicated that Montana-Dakota's pay rates
13 were below the competitive markets. Beginning in 2003, we undertook a
14 phase-in approach to bring our pay rates for non-union personnel more in
15 line with the market.

16 With regard to benefit costs, pension costs have been increasing
17 steadily for most, if not all companies and are expected to continue to
18 increase. Our pension cost requirements are determined at least annually
19 by an independent outside actuarial firm. Finally, medical and health care
20 costs continue to rise.

21 Q. Would you please explain what efforts Montana-Dakota takes to hold its
22 gas rates down?

1 A. We continue to look for ways of operating our business more
2 efficiently and taking advantage of new technologies where it makes
3 economic sense to do so. For example, Montana-Dakota has been
4 proactive in controlling health care costs for many years. Prior to 2003,
5 we limited the Company's share of health care premium increases to a set
6 percentage by shifting additional costs to employees. In 2003 we formed
7 a benefits strategy team to analyze benefits offered to employees and
8 retirees. As a result of that process we implemented certain changes to
9 help mitigate rising health care costs. Changes included,

- 10 • shifting more prescription drug costs, the area where medical
11 inflation has hit the hardest, to employees,
- 12 • changed coordination of benefits to eliminate 100 percent payment
13 on claims for individuals covered by two insurance plans,
- 14 • changed plan administrators, and
- 15 • self-funded all health plans, which eliminates certain costs
16 associated with fully insured plans and provides greater flexibility in
17 plan design.

18 Although we continue to look for opportunities to reduce costs and
19 increase efficiencies, we now find ourselves in a position where, despite
20 our efforts, we must seek rate relief.

21 Q. Is Montana-Dakota seeking interim rate relief in this proceeding?

1 A. Yes. Interim rate relief is being sought in this case consistent with
2 North Dakota Century Code 49-05-06. The amount of interim relief
3 sought is \$1,870,978.

4 Q. Will you please identify the other witnesses who will testify on behalf of
5 Montana-Dakota in this proceeding?

6 A. Yes. In addition to myself, Mr. J. Stephen Gaske, President of
7 Zinder Companies, Inc., will testify regarding the appropriate cost of
8 common equity and overall cost of capital for Montana-Dakota's electric
9 operations. Mr. Craig A. Keller, Vice President, Controller and Chief
10 Accounting Officer for Montana-Dakota will testify regarding the capital
11 structure and overall debt and preferred equity costs. Ms. Rita A. Mulkern,
12 Regulatory Analysis Manager for Montana-Dakota, will testify regarding
13 the total revenue requirements necessary for Montana-Dakota's North
14 Dakota gas operations. Mr. Paul W. Conley, Principal with Towers Perrin,
15 will testify regarding the Supplemental Income Security Plan and Ms.
16 Tamie A. Aberle, Pricing and Tariff Manager for Montana-Dakota, will
17 testify on the rate design proposals.

18 Q. Mr. Imsdahl, are the rates requested in this proceeding just and
19 reasonable?

20 A. Yes. In my opinion, the proposed rates are just and reasonable
21 because they are reflective of the total costs being incurred by Montana-
22 Dakota in providing gas service to its customers. The proposed rates will

1 allow Montana-Dakota the opportunity to earn a just and reasonable return
2 on its North Dakota gas operations.

3 Q. Does this complete your direct testimony?

4 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-_____

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

1 **Q1. Please state your name, position and business address.**

2 A. My name is J. Stephen Gaske and I am President of Zinder Companies,
3 Inc., 7508 Wisconsin Avenue, Suite 300 Bethesda, MD 20814.

4 **Q2. Would you please describe your educational and professional background?**

5 A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree
6 with a major in finance and investments from George Washington University. I also
7 received a Ph.D. degree from Indiana University where my major field of study was
8 public utilities and my supporting fields were in finance and economics.

9 From 1977 to 1980, I worked for H. Zinder & Associates as a research
10 assistant and later as supervisor of regulatory research. In 1980 and 1981, I was
11 employed by Olson and Company where my primary duties were to assist in the
12 preparation of cost of capital studies for presentation in regulatory proceedings.

13 From 1982 to 1986 I undertook graduate studies in economics and finance
14 at Indiana University where I also taught courses in public utilities, transportation,
15 and physical distribution. During this time I also was employed as an independent
16 consultant on a number of projects involving public utility regulation, rate design,
17 and cost of capital. From 1983-1986 I was coordinator for the Edison Electric
18 Institute Electric Rate Fundamentals course. In 1986 I accepted an appointment as

1 assistant professor at Trinity University in San Antonio, Texas, where I taught
2 courses in financial management, investments, corporate finance, and corporate
3 financial theory.

4 In 1988 I returned to H. Zinder & Associates as a consultant. I have
5 testified or filed testimony or affidavits before the Federal Energy Regulatory
6 Commission on more than twenty occasions. Topics covered in these
7 submissions have included rate of return, capital structure, cost allocation, rate
8 design, revenue requirements and market power. I also have filed testimony on
9 the cost of capital and capital structure issues for electric, gas distribution and oil
10 and gas pipeline operations before seven state regulatory bodies, including the
11 North Dakota Public Service Commission, and before the Comision Reguladora
12 de Energia de México (“CRE”). In addition, I have testified or submitted
13 testimony on issues such as cost allocation, rate design, pricing and generating
14 plant economics before the Postal Rate Commission and five state public utility
15 Commissions. During the course of my consulting career, I have conducted many
16 studies on issues related to regulated industries and have served as an advisor to
17 numerous clients on economic, competitive and financial matters. I also have
18 spoken and lectured before many professional groups including the American Gas
19 Association and the Edison Electric Institute Rate Fundamentals courses.

20

1 **I. INTRODUCTION**

2 Scope and Overview

3 **Q3. What is the scope of your testimony in this proceeding?**

4 A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota") to
 5 present the required overall rate of return for the company's natural gas distribution
 6 operations in the state of North Dakota and to determine the cost of common equity
 7 capital for those operations. In this testimony, I calculate the cost of common equity
 8 capital for Montana-Dakota's natural gas distribution operations based on a
 9 Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have
 10 risks similar to those of Montana-Dakota's North Dakota natural gas distribution
 11 operations. The results of this DCF study are supported by various benchmark
 12 criteria that I have used to test the reasonableness of the DCF study results.

13 **Q4. What rate of return is Montana-Dakota requesting in this proceeding?**

14 A. Based on its test period gas utility capital structure, Montana-Dakota is
 15 requesting the following rate of return:

16

Source	Amount (000s)	Percent	Cost	Overall Rate of Return
Long-Term Debt	\$153,350.0	43.535%	8.518%	3.708%
Preferred Stock	\$16,050.0	4.557%	4.614%	0.210%
Common Equity	\$182,843.0	51.908%	11.500%	5.969%
TOTAL	<u>\$352,243.0</u>	<u>100.00%</u>		<u>9.887%</u>

17

18 As my testimony discusses, an overall allowed rate of return of 9.887 percent,
 19 with an 11.50 percent return on common equity, represents the cost of capital for
 20 Montana-Dakota.

Company Background

1
2 **Q5. Would you please describe Montana-Dakota's operations and those of its**
3 **parent company, MDU Resources Group, Inc.?**

4 A. Montana-Dakota is a wholly-owned division of MDU Resources Group,
5 Inc. ("MDU Resources") that is engaged in the generation, transmission and
6 distribution of electricity, and the distribution of natural gas, in the states of North
7 Dakota, Montana, South Dakota and Wyoming. Through other divisions and
8 subsidiaries, MDU Resources is engaged in natural gas exploration, production
9 and transmission and also produces and markets aggregates and other construction
10 materials. MDU Resources also has subsidiaries engaged in utility infrastructure
11 construction, and has Great Plains Natural Gas Company ("Great Plains"), a
12 company that distributes natural gas in southeastern North Dakota and western
13 Minnesota.

14 In 2003, Montana-Dakota and the much smaller Great Plains served a
15 total of 244,000 residential, commercial and industrial gas distribution customers.
16 As shown on Exhibit No. ____ (JSG-2), Schedule 2, page 1, Montana-Dakota's
17 natural gas distribution assets comprised 7.0 percent of MDU Resources' total
18 assets. In addition, the natural gas distribution utility revenues and operating
19 income accounted for 11.5 percent and 1.5 percent of MDU Resources' total,
20 respectively. North Dakota accounted for 39 percent of the natural gas
21 distribution utility operating revenues, while Montana (25 percent), South Dakota
22 (19 percent), Wyoming (6 percent) and Minnesota (11 percent) accounted for the
23 other 61 percent of natural gas distribution utility revenues.

1 **II. FINANCIAL MARKET STUDIES**

2 Criteria for a Fair Rate of Return

3 **Q6. Please describe the criteria which should be applied in determining a fair**
4 **rate of return for a regulated company?**

5 A. The United States Supreme Court has provided general guidance regarding
6 the level of allowed rate of return that will meet constitutional requirements. In
7 *Bluefield Water Works & Improvement Company v. Public Service Commission of*
8 *West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

9
10 "The return should be reasonably sufficient to assure confidence
11 in the financial soundness of the utility and should be adequate,
12 under efficient and economical management, to maintain and
13 support its credit and enable it to raise the money necessary for
14 the proper discharge of its public duties. A rate of return may be
15 reasonable at one time and become too high or too low by
16 changes affecting opportunities for investment, the money market
17 and business conditions generally."

18
19 The Court has further elaborated on this requirement in its decision in *Federal*
20 *Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)).

21 There the Court described the relevant criteria as follows:

22 "From the investor or company point of view it is important that
23 there be enough revenue not only for operating expenses but also
24 for the capital costs of the business. These include service on the
25 debt and dividends on the stock.... By that standard the return to
26 the equity owner should be commensurate with returns on
27 investments in other enterprises having corresponding risks. That
28 return, moreover, should be sufficient to assure confidence in the
29 financial integrity of the enterprise, so as to maintain its credit and
30 to attract capital."

1 Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three
2 requirements. These are that the allowed rate of return should be:

- 3 1. commensurate with returns on enterprises with
4 corresponding risks;
- 5 2. sufficient to maintain the financial integrity of the
6 regulated company; and,
- 7 3. adequate to allow the company to attract capital on
8 reasonable terms.

9 These legal criteria will be satisfied best by employing the economic concept of the
10 "cost of capital" or "opportunity cost" in establishing the allowed rate of return on
11 common equity. For every investment alternative, investors consider the risks
12 attached to the investment and attempt to evaluate whether the return they expect to
13 earn is adequate for the risks undertaken. Investors also consider whether there
14 might be other investment opportunities that would provide a better return relative to
15 the risk involved. This weighing of alternatives and the highly competitive nature of
16 capital markets causes the prices of stocks and bonds to adjust in such a way that
17 investors can expect to earn a return that is just adequate for the risks involved.
18 Thus, for any given level of risk there is a return that investors must expect in order
19 to induce them to voluntarily undertake that risk and not invest their money
20 elsewhere. That return is referred to as the "opportunity cost" of capital or "investor
21 required" return.

22 **Q7. How should a fair rate of return be evaluated from the standpoint of**
23 **consumers and the public?**

24 A. The same standards should apply. When a regulated entity faces
25 competition, consumers will implicitly determine the fair rate of return by their

1 consumption decisions. When regulation is appropriate, consumers and the public
2 have a long-term interest in seeing that the regulated company has an opportunity to
3 earn returns that are not so high as to be excessive, but that also are sufficient to
4 encourage continued replacement and maintenance, as well as needed expansions,
5 extensions, and new services. Thus, the consumer and public interest also lies in
6 establishing a return that will readily attract capital without being excessive.

7 **Q8. How are the costs of preferred stock and long-term debt determined?**

8 A. For purposes of setting regulated rates, the current, embedded costs of
9 preferred stock and long-term debt are used in order to ensure that the company
10 receives a return that is sufficient to pay the fixed dividend and interest obligations
11 that are attached to these sources of capital.

12 **Q9. How is the cost of common equity determined?**

13 A. The practice in setting a fair rate of return on common equity is to use the
14 current market cost of common equity in order to ensure that the return is adequate
15 to attract capital and is commensurate with returns available on other investments
16 with similar levels of risk. However, determining the market cost of common equity
17 is a relatively complicated task that requires analysis of many factors and some
18 degree of judgment by an analyst. The current market cost of capital for securities
19 that pay a fixed level of interest or dividends is relatively easy to determine. For
20 example, the current market cost of debt for publicly-traded bonds can be calculated
21 as the yield-to-maturity, adjusted for flotation costs, based on the current market
22 price at which the bonds are selling. In contrast, because common stockholders
23 receive only the residual earnings of the company, there are no fixed contractual

1 payments which can be observed. This high degree of uncertainty associated with
2 the dividends that eventually will be paid greatly complicates the task of estimating
3 the cost of common equity capital. For purposes of this testimony, I have relied on
4 several analytical approaches for estimating the cost of common equity. My primary
5 approach relies on several DCF analyses. In addition, I have conducted Risk
6 Premium and Alternative Equity Investment analyses in order to establish
7 benchmarks for a reasonable rate of return. Each of these approaches are described
8 later in this testimony.

9 Cost of Debt

10 **Q10. What debt cost rates have you used for Montana-Dakota?**

11 A. Calculation of the overall cost of long-term debt and the effective cost of
12 each of the long-term debt issues is shown in the Prepared Direct Testimony of
13 Craig Keller, Vice President, Controller, and Chief Accounting Officer for
14 Montana-Dakota.

15 **Q11. What cost of preferred stock did you use?**

16 A. Montana-Dakota's annual cost of preferred stock is 4.614 percent, as
17 shown also in the Prepared Direct Testimony of Craig Keller.

18 Interest Rates and the Economy

19 **Q12. What are the general economic factors that affect the cost of capital?**

20 A. Investors are often influenced by their perceptions of the economy and both short-
21 and long-term trends. Page 1 of Schedule 1 of Exhibit No.____(JSG-2) shows
22 various general economic statistics. The economy has had a record of persistent

1 growth during the past thirty years, with only temporary recessionary periods. Real
2 growth in the Gross Domestic Product ("GDP") has averaged 3.1 percent annually
3 during the past 30 years, 3.1 percent for the past 20 years and 3.2 percent for the past
4 ten years. After growing slowly during 2002 and the first half of 2003, the economy
5 has been growing at an exceptionally rapid rate lately. For example, the U.S. GDP
6 grew at an annual rate of 8.2 percent during the third quarter of 2003. Stock prices
7 in general have increased recently, but many energy companies have seen their stock
8 prices plummet during the past two years. There has been a marked increase in the
9 perceived risk of common equity investments in general and also an increase in the
10 perceived risk of energy and utility-related investments in particular.

11 Investors also are influenced by the level of inflation, which has been
12 persistent in the past. During the past decade, the Consumer Price Index has
13 increased at an average annual rate of 2.6 percent and the GDP Implicit Price
14 Deflator, a measure of price changes for all goods produced in the United States, has
15 increased at an average rate of 1.9 percent.

16 Companies attempting to attract common equity must compete with a
17 variety of alternative investments. Prevailing interest rates provide a standard
18 measure of returns currently available on less risky securities. As Page 2 of
19 Schedule 1 of Exhibit No. ___(JSG-2) shows, long-term interest rates have
20 remained relatively stable during the past two years. This relative stability of
21 long-term interest rates is in stark contrast to the large decline in short-term
22 interest rates that occurred during this same time period. The recent yields on A-

1 rated public utility bonds have been approximately 6.3 percent and the yields on
2 Baa-rated public utility bonds have been approximately 6.6 percent.

3 Discounted Cash Flow (“DCF”) Method

4 **Q13. Please describe the DCF method of estimating the cost of common equity**
5 **capital.**

6 A. The DCF method reflects the assumption that the market price of a share of
7 stock represents the discounted present value of the stream of all future dividends
8 that investors expect the firm to pay. The DCF method suggests that investors in
9 common stocks expect to realize returns from two sources: a current dividend yield,
10 plus expected growth in the value of their shares as a result of future dividend
11 increases. Estimating the cost of capital with the DCF method therefore is a matter
12 of calculating the current dividend yield and estimating the long-term future growth
13 rate in dividends that investors reasonably expect from a company.

14 The dividend yield portion of the DCF method utilizes readily-available
15 information regarding stock prices and dividends. The market price of a firm's stock
16 reflects investors' assessments of risks and potential earnings as well as their
17 assessments of alternative opportunities in the competitive financial markets. By
18 using the market price to calculate the dividend yield, the DCF method implicitly
19 recognizes investors' market assessments and alternatives. However, the other
20 component of the DCF formula, investors' expectations regarding the future long-run
21 growth rate of dividends, is not readily apparent from stock market data and must be
22 estimated using informed judgment.

1 **Q14. What is the appropriate DCF formula to use in this proceeding?**

2 A. There can be many different versions of the basic DCF formula,
 3 depending on the assumptions that are most reasonable regarding the timing of
 4 future dividend payments. In my opinion, it is most appropriate to use a model
 5 that is based on the assumptions that dividends are paid quarterly and that the next
 6 annual dividend increase is a half year away. One version of this quarterly model
 7 assumes that the next dividend payment will be received in three months, or one
 8 quarter. This model multiplies the dividend yield by $(1 + .75 g)$. Another version
 9 assumes that the next dividend payment will be received today. This model
 10 multiplies the dividend yield by $(1 + .5 g)$. Since, on average, the next dividend
 11 payment is a half quarter away, the average of the results of these two models is a
 12 reasonable approximation of the average timing of dividends and dividend
 13 increases that investors can expect from companies that pay dividends quarterly.
 14 The average of these two quarterly dividend models is:

$$K = \frac{D(1 + .625g)}{P} + g \quad (1)$$

15
 16
 17
 18 where: K = the cost of capital, or total return that investors expect to
 19 receive;

20
 21 P = the current market price of the stock;

22
 23 D = the current annual dividend rate; and

24
 25 g = the future annual growth rate that investors expect.

26 In my opinion, this is the DCF model that is most appropriate for estimating the
 27 cost of common equity capital for companies that pay dividends quarterly, such as
 28 those used in my analysis.

1

Flotation Cost Adjustment

2

Q15. Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?

3

4 A.

Yes. There are significant costs associated with issuing new common equity capital and these costs must be considered in determining the cost of capital.

5

6

Schedule 3 of Exhibit No. ___(JSG-2) shows a representative sample of flotation

7

costs incurred with 34 new common stock issues by natural gas transmission and

8

distribution companies between 1992 and 2002. Flotation costs associated with

9

these new issues averaged 4.77 percent. This indicates that in order to be able to

10

issue new common stock on reasonable terms, without diluting the value of the

11

existing stockholders' investment, Montana-Dakota must have an expected return

12

that places a value on its equity that is approximately 4.75 percent above book value.

13

The cost of common equity capital is therefore the investor return requirement

14

multiplied by 1.0475.

15

One purpose of a flotation cost adjustment is to compensate common

16

equity investors for past flotation costs by recognizing that their real investment in

17

the company exceeds the equity portion of the rate base by the amount of past

18

flotation costs. For example, the proxy companies generally have incurred flotation

19

costs in the past and, thus, the cost of capital invested in these companies is the

20

investor return requirement plus an adjustment for flotation costs. A more important

21

purpose of a flotation cost adjustment is to establish a return that is sufficient to

22

enable a company to attract capital on reasonable terms. This fundamental

23

requirement of a fair rate of return is analogous to the well-understood basic

1 principle that a firm, or an individual, should maintain a good credit rating even
2 when they do not expect to be borrowing money in the near future. Regardless of
3 whether a company can confidently predict its need to issue new common stock
4 several years in advance, it should be in a position to do so on reasonable terms at all
5 times without dilution of the book value of the existing investors' common equity.
6 This requires that the flotation cost adjustment be applied to the entire common
7 equity investment and not just a portion of it.

8 **Q16. Has MDU Resources recently needed to raise additional common equity capital**
9 **through a stock offering?**

10 A. In February 2004 MDU Resources raised approximately \$51 million
11 through a common stock offering. Due to some cost savings as a result of a recent
12 bond issue that reduced the cost of an additional underwriting review, the flotation
13 costs of that issuance were only 4.2 percent. However, my studies indicate that the
14 expected costs of a future issue under normal circumstances would be approximately
15 4.75 percent.

16 DCF Study of Natural Gas Distribution Companies

17 **Q17. Would you please describe the overall approach used in your DCF analysis of**
18 **Montana-Dakota's cost of common equity?**

19 A. Because Montana-Dakota must compete for capital with many other
20 potential projects and investments, it is essential that it have an allowed return that
21 matches returns potentially available from other similarly risky investments. The
22 DCF method provides a good measure of the returns required by investors in the
23 financial markets. However, the DCF method requires a market price of common

1 stock to compute the dividend yield component of the DCF analysis. Since
2 Montana-Dakota is a division of MDU Resources and does not have publicly-traded
3 common stock, a direct, market-based DCF analysis of Montana-Dakota's natural
4 gas distribution operation as a stand-alone company is not possible. Consequently, I
5 selected a group of natural gas distribution companies with publicly-traded common
6 stock as a proxy group for purposes of estimating the cost of common equity for
7 Montana-Dakota's North Dakota natural gas distribution operations.

8 **Q18. How did you select your group of proxy companies?**

9 A. In Montana-Dakota's 2002 rate case, the Commission expressed a desire
10 for a proxy group with a somewhat greater number of companies. Consequently, I
11 utilized three criteria in selecting the proxy group. First, a company must be listed
12 as a natural gas distribution company by Value Line to ensure that retention growth
13 rate forecasts would be available and that the company is considered to be primarily
14 a natural gas distribution company. Next, companies with bond ratings that are
15 below investment grade were eliminated because such companies are not
16 sufficiently comparable to Montana-Dakota. Finally, those companies for which
17 Zack's long-term growth rate projections are not available were eliminated. These
18 criteria produced the group of 10 companies shown on Schedule 2 of Exhibit No.
19 ___(JSG-2).

20 **Q19. How did you calculate the dividend yields for the companies in your**
21 **comparison group?**

22 A. These calculations are shown on page 3 of Schedule 2 of Exhibit No.
23 ___(JSG-2). For the price component of the calculation I used the average of the high

1 and low stock prices experienced by each company during the six month period
2 from July 2003 to December 2003. The dividend yields were calculated for each
3 company by dividing the indicated annual dividend by the average of the stock
4 prices for each company. These dividend yields can be multiplied by the quarterly
5 DCF model factor $(1 + .625 g)$ to arrive at the dividend yield component of the DCF
6 model.

7 **Q20. Please describe the method you used in estimating the future growth rate that**
8 **investors expect from this group of companies?**

9 A. I developed three different DCF analyses of the proxy companies based on
10 three different growth rate estimation methods. There are many methods that
11 reasonably can be employed in formulating a growth rate estimate, but an analyst
12 must attempt to ensure that the end result is an estimate that fairly reflects the
13 forward-looking growth rate that investors expect.

14 In the first approach I calculated a DCF rate of return using a combination
15 of securities analysts' growth projections and the Value Line retention growth
16 forecasts to produce a Second-Stage Retention Growth analysis. As a second
17 approach, I conducted a Basic DCF analysis that relied solely on the analysts'
18 forecasts for the growth rate component of the model. Finally, my Primary DCF
19 uses a variety of sources and analyses to develop an estimate of the composite
20 growth rate that investors would expect from the sample group of proxy companies.

1 Second-Stage Retention Growth Analysis

2 **Q21. How did you use your Second-Stage Retention Growth analysis to estimate**
3 **investors' long-term growth rate expectations for the proxy companies?**

4 A. The Second-Stage Retention Growth rate approach combines: (i) estimates
5 of long-term growth for each company that are published by various investment
6 analysts and (ii) Value Line retention growth forecasts.

7 **Q22. How did you estimate the first stage of expected future growth?**

8 A. Among the best sources of information regarding investors' growth rate
9 expectations are the long-term earnings growth rate forecasts of investment analysts.
10 Zack's is a service that collects estimates by professional investment analysts and
11 publishes a summary of the consensus forecasts. I have used the Zack's consensus
12 forecasts as the source for analysts' forecasts in my calculations. As shown on
13 Exhibit No. ___ (JSG-2), Schedule 2, page 5, the average of the analysts' long-
14 term growth rate estimates for the natural gas distribution proxy companies is 5.6
15 percent.

16 **Q23. Would you please describe the second stage, retention growth rate component**
17 **of your analysis?**

18 A. In addition to analysts' growth rate forecasts, I have relied upon Value
19 Line projections of the retention growth rates that the proxy companies are
20 expected to begin maintaining three to five years in the future. Although
21 companies may experience extended periods of growth for other reasons, in the
22 long-run, growth in earnings and dividends per share depends in part on the amount
23 of earnings that are being retained and reinvested in a company. Thus, the primary

1 determinants of growth for the proxy companies will be (i) their ability to find and
2 develop profitable opportunities; (ii) their ability to generate profits that can be
3 reinvested in order to sustain growth; and, (iii) their willingness and inclination to
4 reinvest available profits. Expected future retention rates provide a general measure
5 of these determinants of expected growth, particularly items (ii) and (iii).

6 **Q24. How can a company's earnings retention rate affect its future growth?**

7 A. Retention of earnings causes an increase in the book value per share and,
8 other factors being equal, increases the amount of earnings that are generated per
9 share of common stock. The retention growth rate can be estimated by multiplying
10 the expected retention rate (b) times the rate of return on common equity (r) that a
11 company is expected to earn in the future. For example, a company that is expected
12 to earn a return of 15 percent and retain 80 percent of its earnings might be expected
13 to have a growth rate of 12 percent, computed as follows:

$$.80 \times 15\% = 12\%$$

15 On the other hand, another company that is also expected to earn 15 percent but only
16 retains 20 percent of its earnings might be expected to have a growth rate of 3
17 percent, computed as follows:

$$.20 \times 15\% = 3\%$$

19 Thus, the rate of growth in a firm's book value per share is primarily determined by
20 the level of earnings and the proportion of earnings retained in the company.

1 **Q25. How did you calculate the expected future retention rates of the proxy**
2 **companies?**

3 A. For most companies, Value Line publishes forecasts of data that can be
4 used to estimate the retention rates that its analysts expect individual companies to
5 have 3-5 years in the future. Since these retention rates are projected for several
6 years in the future they should be indicative of a normal expectation for a primary
7 underlying determinant of growth that would be sustainable indefinitely beyond the
8 period covered by analysts' forecasts. While companies may have either
9 accelerating or decelerating growth rates for extended periods of time, the retention
10 growth rates expected to be in effect 3-5 years in the future generally represent a
11 minimum "cruising speed" that companies can be expected to maintain indefinitely.
12 The derivation of Value Line's retention growth rate forecasts for each of the proxy
13 companies is shown on page 4 of Schedule 2 of Exhibit No.__(JSG-2). The
14 projected earnings per share and projected dividends per share can be used to
15 calculate the percentage of earnings per share that are being retained and reinvested
16 in the company. This earnings retention rate is multiplied times the projected return
17 on common equity to arrive at the projected retention growth rate. The average
18 retention growth rate for the proxy companies is 5.8 percent.

19 **Q26. How did you utilize the projected earnings retention rates in estimating**
20 **expected growth for the proxy companies?**

21 A. As shown on page 5 of Schedule 2 of Exhibit No.__(JSG -2), I calculated
22 a weighted average of the analysts' projected growth rates and the projected
23 retention growth rates to derive long-term growth rate estimates for each of the

1 proxy companies. In these calculations, I gave a two-thirds weighting to the
2 analysts' growth rate projections to reflect the fact that analysts are attempting to
3 evaluate all sources of growth and not just growth that is expected to result from
4 retained earnings. This weighting also reflects the fact that the analysts' long-term
5 growth forecasts can be expected to prevail for a relatively long period of time in the
6 future. This two-thirds weighting for analysts' forecasts is the same weighting
7 that the FERC used in Opinion No. 414-A for setting the allowed return on equity
8 for natural gas pipeline companies. *Transcontinental Gas Pipeline Co.*, 80 FERC
9 ¶ 61,084 (1998). The average of the weighted average growth rates for the proxy
10 companies is 5.6 percent and the median is 5.4 percent.

11 **Q27. How did you utilize these Second-Stage Retention Growth rate estimates in**
12 **estimating the return on common equity capital that investors require from**
13 **the proxy companies?**

14 A. The dividend yield for each company shown on page 3 of Schedule 2 of
15 Exhibit No.____(JSG-2) is multiplied times the quarterly dividend adjustment factor
16 $(1 + .625g)$ and this product is added to the growth rate estimate to arrive at the
17 investor-required return. Finally, the investor return requirement is multiplied times
18 the flotation cost adjustment factor, 1.0475 to arrive at the cost of common equity
19 capital for the proxy companies. These calculations are shown on page 6 of
20 Schedule 2 of Exhibit No.____(JSG-2). This Second-Stage Retention Growth DCF
21 analysis indicates that the cost of common equity capital for the natural gas
22 distribution proxy companies is in a range between 9.2 percent and 12.7 percent.

1 The median for the group is 10.6 percent and the average for the group is 10.5
2 percent.

3 Basic DCF Analysis

4 **Q28. What approach did you use in conducting a Basic DCF analysis?**

5 A. This analysis is conducted in substantially the same manner as the Second-
6 Stage Retention Growth Rate analysis. However, the growth rate component of the
7 analysis is based solely on the analysts' forecasts for each company and the retention
8 growth rate component is omitted from the analysis. This Basic DCF analysis
9 recognizes that the consensus of analysts' forecasts reflects the most important
10 component of investors' growth rate expectations and it assumes that the analysts'
11 forecasts incorporate all information required to estimate a long-term expected
12 growth rate for a company.

13 **Q29. How did you calculate the cost of capital using the Basic DCF analysis?**

14 A. These calculations are shown on page 7 of Schedule 2 of Exhibit
15 No.__(JSG-2). Again, the annual dividend yield is multiplied times the quarterly
16 dividend adjustment factor $(1 + .625g)$ and this product is added to the growth rate
17 estimate to arrive at the investor-required return. Then, the investor return
18 requirement is multiplied times the flotation cost adjustment factor, 1.0475 to arrive
19 at the Basic DCF estimate of the cost of common equity capital for the proxy
20 companies. The Basic DCF analysis indicates a median and average cost of
21 common equity for the proxy companies of 10.4 percent.

1

Primary DCF Analysis2 **Q30. Would you please describe your Primary DCF analysis?**

3 A. My primary DCF approach refines the growth rate estimates to reflect my
4 analysis of the appropriate range of growth rate expectations that are implicit in the
5 stock prices and dividend yields of this group. As the following analysis indicates,
6 my primary analysis indicates a DCF required rate of return that is quite close to the
7 level that is indicated by both the Second-Stage Retention Growth DCF analysis and
8 the Basic DCF analysis.

9 **Q31. In your opinion, what are the factors that will affect growth rates for the**
10 **proxy companies in the future?**

11 A. One important factor will be growth in the overall economy. Page 1 of
12 Schedule 1 of Exhibit No. ___(JSG-2) shows that the United States Gross Domestic
13 Product has grown at an average annual rate of 7.4 percent during the past 30 years.
14 During the past decade U.S. GDP growth has averaged 5.2 percent. It is reasonable
15 to expect that long-term future growth in the economy generally will be comparable
16 to past growth rates.

17 Another factor will be demand for natural gas. Natural gas usage has been
18 increasing in recent years and many analysts are expecting demand to increase
19 steadily during the next decade and beyond. For example, the Energy Information
20 Administration of the U.S. Department of Energy forecasts that gas consumption in
21 the United States will grow from its current level of approximately 22 Tcf per year
22 to approximately 33 Tcf per year in 2020. While the real gas distribution capacity of
23 the proxy companies is expected to increase, additional growth will occur because

1 the amount of investment required will increase in nominal dollars. In other words,
2 the effects of inflation needs to be added to the real growth rate in the industry to get
3 a measure of likely growth in investment and earnings.

4 In my opinion, investors reasonably expect the 10 companies in this
5 comparison group to grow at a rate that is somewhere in the range of 5.0 percent to
6 6.5 percent. Based on the average growth rate of approximately 5.6 percent
7 currently projected by investment analysts, as well as the 6.0 percent long-term
8 future growth rate in the economy forecast by DRI-WEFA, increasing demands for
9 natural gas, and my review of these companies, I consider this growth rate range to
10 be a reasonable estimate of the future growth expectations that are implicit in current
11 dividend yields. This growth rate range is also consistent with the retention growth
12 rates projected for these companies and their ability to grow by means other than
13 retained earnings.

14 **Q32. What does your primary DCF analysis indicate with regard to investors'**
15 **current market rate of return requirements?**

16 A. Page 8 of Schedule 2 of Exhibit No. ___(JSG-2) shows the calculation of
17 the cost of capital based on my primary DCF growth rate estimates. The dividend
18 yield used in this analysis is the average dividend yield for the natural gas
19 distribution proxy companies that is developed on page 3 of Schedule 2. This
20 market-based primary DCF analysis indicates that the cost of capital for the proxy
21 companies is approximately in the range of **9.9 percent to 11.5 percent.**

Risk Premium Analyses

1

2 **Q33. Have you conducted additional analyses in determining the cost of capital to**
3 **Montana-Dakota?**

4 A. Yes. The risk premium approach provides a general guideline for
5 determining the level of returns that investors expect from an investment in common
6 stocks. Investments in the common stocks of companies carry considerably greater
7 risk than investments in bonds of those companies since common stockholders
8 receive only the residual income that is left after the bondholders have been paid. In
9 addition, in the event of bankruptcy or liquidation of the company, the stockholders'
10 claims on the assets of a company are subordinated to the claims of bondholders.
11 This superior standing provides bondholders with greater assurances that they will
12 receive the return on investment that they expect and that they will receive a return
13 of their investment when the bonds mature. Accompanying the greater risk
14 associated with common stocks is a requirement by investors that they can expect to
15 earn, on average, a return that is greater than the return they could earn by investing
16 in less risky bonds. Thus, the risk premium approach estimates the return investors
17 require from common stocks by utilizing current market information that is readily
18 available in bond yields and adding to those yields a premium for the added risk of
19 investing in common stocks.

20 Investors' expectations for the future are influenced to a large extent by
21 their knowledge of past experience. Ibbotson Associates annually publishes
22 extensive data regarding the returns that have been earned on stocks, bonds and U.S.
23 Treasury bills since 1926. Historically, the annual returns on large company

1 common stocks have exceeded the returns on Long-Term U.S. Government Bonds
2 by an average of 640 basis points (6.40 percent). However, the returns on relatively
3 small company stocks in the size range of Montana-Dakota's natural gas distribution
4 operations have been 1,130 basis points (11.3 percent) above the yields on long-term
5 government bonds. As shown on page 1 of Schedule 2 of Exhibit No. ____ (JSG-2),
6 Montana-Dakota is a fraction of the size of any of the proxy companies. In recent
7 months, the yield on long-term U.S. Government bonds has been approximately 5.0
8 percent. Adding a 6.4 percent premium to a yield of 5.0 percent indicates that
9 investors in large company common stocks expect a return of at least 11.4 percent.
10 Adding the 11.3 percent premium for companies in Montana-Dakota's size range
11 suggests a required return of 16.3 percent.

12 Another risk premium approach is to examine the long-term premium of
13 large company common stock returns as compared with returns on corporate bonds.
14 This premium has averaged 600 basis points (6.0 percent) annually over a long
15 period of time in the past. When this premium is added to the 6.2 percent yield on
16 Moody's corporate bonds that has prevailed in recent months, the result is an
17 investor return requirement for large company stocks of 12.2 percent. However,
18 over the long term companies in Montana-Dakota's size range have had a premium
19 of 1,090 basis points (10.9 percent) over the average returns on long-term corporate
20 bonds. When added to the recent average corporate bond yields, this size-related
21 premium suggests an expected return of 17.1 percent.

Alternative Equity Investment Analysis

1
2 **Q34. Have you analyzed the returns available on common equity investments in**
3 **other industries?**

4 A. Yes. When investors consider whether to invest their funds in a particular
5 company or line of business, they evaluate the returns potentially available from
6 other companies. This process whereby projects and companies compete for scarce
7 equity capital ensures that capital resources are deployed efficiently. As a result,
8 regulated natural gas distribution operations must bid against other companies and
9 other possible projects within the same company for equity capital by offering
10 potential returns that investors find attractive relative to the risks involved.

11 **Q35. What level of returns are potentially available to unregulated companies?**

12 A. The potential returns are often considerably above 20 percent and the
13 average returns for broad-based, diversified portfolios have averaged 20.0 percent or
14 more in recent years. For example, page 3 of Schedule 1 of Exhibit No. ___(JSG-2)
15 shows the average return on equity book value earned by companies in the S&P 500
16 each year from 1977 to 2000. It can be seen, in fact, that average returns for the
17 S&P 500 companies have been 21.47 percent for the past five years. For purposes
18 of comparison with allowed returns for regulated natural gas distribution operations,
19 a better indicator of earnings on alternative equity investments is provided by data
20 on 746 industrial, retail and transportation companies published by *The Value Line*
21 *Investment Survey*. Excluding extraordinary and non-recurring items, the average
22 returns on the original cost book value of common equity for these companies in
23 recent years has been:

1	1998	29.12%
2	1999	30.35
3	2000	32.17
4	2001	24.88
5	2002	26.23
6		
7	5-year Average	28.55%
8		

9 **Q36. Is it appropriate to set the allowed rate of return for a natural gas**
10 **distribution company equal to the average return available to industrial**
11 **companies?**

12 A. The average return for industrials serves as a useful indicator of the cost of
13 capital because natural gas distribution companies must offer potential returns that
14 are competitive with other investments in order to attract capital. It is important to
15 remember that an industrial company has an opportunity to earn returns far in excess
16 of 20 percent. In fact, the average company has earned normal returns on the book
17 value of equity well in excess of 20 percent in recent years. This average reflects
18 many companies that experienced enormous losses as well as those with large
19 returns.

20 Similarly, when a regulator sets an allowed return it is providing only an
21 *opportunity* to earn that return. In exceptionally good times a regulated company
22 might earn slightly more than this amount, but it might earn substantially less than
23 the allowed return and, in fact, often does earn less than that amount. Natural gas
24 distribution companies generally have risks that are less than those of the average
25 large industrial company. Consequently, it would be appropriate to view average
26 returns earned by a broad cross-section of industry as being only a general indicator
27 for reasonable allowed returns.

1 enormous uncertainties and risks that demand, costs, supply and competition may
2 change in ways that adversely affect the value of the investment.

3 **Q39. What are some of the business risks faced by Montana-Dakota's North Dakota**
4 **natural gas distribution operations?**

5 A. These operations face many of the same risks that are associated with
6 other natural gas distribution companies. However, Montana-Dakota's gas
7 distribution operation faces some risks that distinguish it from many other
8 distribution companies.

9 As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-
10 Dakota's natural gas distribution operations are considerably smaller than the
11 operations of any of the proxy companies and a small fraction of the size of the
12 typical proxy company. For example, Montana-Dakota's natural gas distribution
13 assets are equal to only 9.1 percent of the assets of the median proxy company.
14 Similarly, Montana-Dakota's gas distribution operating revenues and operating
15 income are only 16.4 percent and 2.4 percent of the level for the median proxy
16 company. Thus, depending upon the measure of size, the typical proxy company
17 is somewhere between approximately six and 42 times the size of Montana-
18 Dakota's natural gas distribution operations.

19 With its small revenue base, Montana-Dakota is subject to slightly
20 greater risk that a major employer or industry, such as a mining operation or
21 refinery, might experience a downturn that would significantly affect overall
22 employment and income in the areas served.

1 Ibbotson Associates has documented the significantly higher returns that
2 generally have been associated with small companies. On a practical level,
3 Montana-Dakota's relatively small natural gas distribution operations are heavily
4 dependent upon a relatively undiversified local economy. Factors that negatively
5 influence the local economy can reduce demand for Montana-Dakota's gas
6 distribution services and adversely impact investments in facilities used to provide
7 those services.

8 In fact, demographic trends cause Montana-Dakota's North Dakota
9 natural gas distribution operations to be significantly riskier than the operations of
10 the utilities in the proxy group. For example, North Dakota ranked 50th among
11 the 50 states in terms of population growth between 1990 and 2000. However,
12 the state-wide average population growth rate masks the fact that North Dakota
13 counties where Montana-Dakota provides gas distribution service are shrinking.
14 This declining population is shown on page 4 of Schedule 1 of Exhibit No.
15 ___(JSG-2). During the past 20 years, the population of counties in which
16 Montana-Dakota provides gas distribution service have experienced population
17 declines of approximately 0.3 percent per year. So far, Montana-Dakota has been
18 able to overcome the effects of a stagnant and shrinking population base by
19 obtaining conversions of customers to natural gas and increasing its market
20 penetration. In addition, there is some migration of population from rural areas to
21 the towns in North Dakota. Nevertheless, a long-term problem and source of risk
22 for Montana-Dakota derives from the fact that its investments in fixed-cost gas
23 distribution facilities are sunk and have a long life. These facilities cannot be

1 easily moved or devoted to another purpose, even if the population declines
2 significantly or gas becomes uneconomical. The population shifts that are
3 occurring in Montana-Dakota's service territory pose a significant risk that it may
4 at some point be unable to recover the cost of its natural gas distribution
5 investments.

6 In addition, the threat of bypass is more significant for a smaller
7 company and the threat is especially great for a company such as Montana-Dakota
8 that is located near a gas production area. Montana-Dakota also faces direct
9 competition from propane and heating oil for new and existing load in its North
10 Dakota service territory. Another risk faced by Montana-Dakota is the fact that it
11 recovers a substantial portion of its fixed costs in the volumetric component of its
12 rates and it does not have a weather normalization adjustment mechanism. In
13 contrast, several of the proxy companies have rate designs that better reflect the
14 fixed cost nature of their operations. These companies have slightly less rate
15 design risk as a result.

16 Considering only its smaller size, Montana-Dakota might require a return
17 that is more than 100 basis points higher than the return required for the typical
18 proxy company. Montana-Dakota also faces somewhat above-average rate design
19 risk. However, most important is the fact that the declining population base in
20 counties served by Montana-Dakota, means that Montana-Dakota's North Dakota
21 natural gas distribution operations are significantly riskier than the operations of
22 the proxy companies.

1 **Q40. What are the regulatory risks faced by Montana-Dakota's North Dakota utility**
2 **operations?**

3 A. Regulatory risk is closely related to business risk and might be
4 considered just another aspect of business risk. To the extent that the market
5 demand for a natural gas distribution company's services is sufficiently strong
6 that the company could conceivably recover all of its costs, regulators may
7 nevertheless set the rates at a level that will not allow full cost recovery. In effect,
8 the binding constraint on utilities is often posed by regulation rather than by the
9 working of market forces. One purpose of regulation is to provide a substitute for
10 competition where markets are not workably competitive. As such, regulation
11 often attempts to replicate the type of cost discipline and risks that might typically
12 be found in highly competitive industries. Moreover, there is the perceived risk
13 that regulators may set allowed returns so low as to effectively undermine
14 investor confidence and jeopardize the ability of gas distribution utilities to
15 finance their operations. Thus, in some instances regulation may substitute for
16 competition and in other instances it may limit the potential returns available to
17 successful competitors. In either case, regulatory risk is an important
18 consideration for investors and has a significant effect on the cost of capital for all
19 firms in the natural gas distribution industry. Value Line rates the regulatory
20 climate in North Dakota as being "average."

21 **Q41. Would you please describe Montana-Dakota's relative financial risks?**

22 A. Financial risk exists to the extent a company incurs fixed obligations in
23 financing its operations. These fixed obligations increase the level of income

1 which must be generated before common stockholders receive any return and
2 serve to magnify the effects of business and regulatory risks. Fixed financial
3 obligations also increase the probability of bankruptcy by reducing the company's
4 financial flexibility and ability to respond to adverse circumstances. One possible
5 indicator of investors' perceptions of relative financial risk in this case might be
6 obtained from bond ratings. Because Montana-Dakota does not have its own
7 bonds outstanding, it is difficult to make direct comparisons between the ratings
8 of Montana-Dakota and the proxy group. However, page 2 of Schedule 2 of
9 Exhibit No. ____ (JSG-2) shows the bond ratings assigned by Moody's and
10 Standard & Poor's to each of the companies in the comparison group and to MDU
11 Resources bonds that are secured by the assets of Montana-Dakota Utilities. The
12 median bond ratings for companies in the proxy group are A for Standard &
13 Poor's and A2 for Mergent. In comparison, MDU Resources bonds carry an A-
14 rating with Standard & Poor's and an A2 rating with Mergent. This suggests that
15 the perceived risk of MDU Resources' bonds is nearly the same as that of the
16 typical company in the comparison group. Examination of the capital structure
17 data shown on page 9 of Exhibit No. ____ (JSG-2), Schedule 2 shows that
18 Montana-Dakota's filed common equity ratio, 51.9 percent, is slightly less than
19 the mean and median common equity ratios of the proxy companies. This
20 common equity ratio, combined with its bond rating, suggests average financial
21 risk for Montana-Dakota's North Dakota natural gas distribution operations.

1 **Q42. Would you please describe Montana-Dakota's market risks?**

2 A. Market risk is associated with the changing value of all investments
3 because of business cycles, inflation and fluctuations in the general cost of capital
4 throughout the economy. Different companies are subject to different degrees of
5 market risk largely as a result of differences in their business and financial risks.
6 Because of the substantial similarity in their operations, Montana-Dakota's degree
7 of market risk is not significantly different from that of the companies in the
8 natural gas distribution comparison group.

9 **Q43. How do the overall risks of the proxy companies compare with the risks
10 faced by Montana-Dakota's natural gas distribution operations?**

11 A. Montana-Dakota faces overall risks that are above average relative to those
12 of the proxy companies. Montana-Dakota has above-average business risks due
13 primarily to its exceptionally small size relative to the proxy companies and its
14 exposure to competition and a relatively undiversified economy. Montana-Dakota
15 also has slightly greater rate design risk than the typical company in the proxy group.
16 As shown on page 4, Schedule 1 of Exhibit No. ___(JSG-2) Montana-Dakota faces
17 unusually high risk because the counties where it provides service are experiencing
18 declining population. In addition, it has financial risks that are average relative to
19 the proxy companies. These factors and the perception of an average regulatory
20 climate in North Dakota lead me to conclude that the overall risks of Montana-
21 Dakota's natural gas distribution operations are well above average relative to the
22 risks of the proxy companies.

1 **III. SUMMARY AND CONCLUSIONS**

2 **Q44. Would you please summarize the results of your cost of capital study?**

3 A. Yes. I conducted several DCF analyses on a group of natural gas
4 distribution companies that have a range of risks that includes risks roughly
5 comparable to those of Montana-Dakota. The results of my various analyses can be
6 summarized as follows:

7

	<u>Cost of Capital Median/Average</u>	<u>Range</u>
<u>DCF Analyses</u>		
Natural gas distribution Proxies:		
- Second-Stage Retention Growth	10.6%/10.5%	9.2%/12.7%
- Basic DCF	10.4%/10.4%	9.2%/11.8%
- Primary DCF	10.7%	9.9%/11.5%
<u>Benchmark Analyses</u>		
<u>Risk Premium Return Based On:</u>		
- U.S. Treasury Bonds		
v. Large Companies	11.4	
v. Small Companies	16.3	
- Corporate Bonds		
v. Large Companies	12.2	
v. Small Companies	17.1	
<u>Alternative Investments</u>		
- S&P 500	21.5	
- Value Line Industrials	28.6	

8

9 My second-stage retention growth analysis indicates a median cost of
10 common equity capital of 10.6 percent and an average cost of 10.5 percent. The
11 range for this analysis is 9.2 percent to 12.7 percent. Because projected retention
12 growth is sustainable indefinitely and it is directly related to the growth rate

1 expectations for an individual company, it is a good indicator of the minimum
2 growth rate that a company can maintain in the very long run. However,
3 companies can achieve growth through means in addition to retained earnings.
4 Consequently, analysts' forecasts provide the best measure of expected growth for
5 the foreseeable future. At this time, the average of the analysts' forecasts and the
6 retention growth forecasts for the proxy companies are identical. Combining
7 these two measures provides a good estimate of the long-term growth that
8 investors can reasonably expect from these proxy companies.

9 The Basic DCF analysis, which relies solely on the analysts' forecasts, also
10 provides a good estimate of investors' growth rate expectations and required return
11 for the proxy companies. This DCF analysis indicates a median required rate of
12 return of 10.4 percent and an average rate of return of 10.4 percent. The range of
13 results for this analysis is 9.2 percent to 11.8 percent.

14 My primary approach has been to analyze a variety of sources of
15 information, including investment analysts' forecasts, in order to estimate a
16 weighted average annual growth rate that investors reasonably can expect the natural
17 gas distribution comparison companies to achieve during a long period of time in the
18 future. This primary DCF analysis indicates that the cost of capital for natural gas
19 distribution companies with risks comparable to those of Montana-Dakota is in a
20 range between 9.9 percent and 11.5 percent. The mid-point of this range is
21 approximately 10.7 percent.

22 My risk premium analyses indicate that my DCF estimates produce a
23 premium over corporate bond yields that is below the average long-run risk

1 premium available from common stocks. The DCF return estimates provide a
2 premium over the return on corporate bonds that is considerably below the
3 average premium experienced by companies in Montana-Dakota's relative size
4 range. In addition, my examination of returns available on alternative equity
5 investments suggests that my DCF estimates are far below the 28.6 percent
6 average normal returns earned by the Value Line Industrials in recent years.

7 **Q45. What rate of return on common equity do you recommend for Montana-**
8 **Dakota in this proceeding?**

9 A. My analyses indicate that an appropriate rate of return on common
10 equity for Montana-Dakota's North Dakota natural gas distribution operations at
11 this time would be **11.50 percent**. A return of 11.50 percent is at the top of the
12 range for my Primary DCF analysis and also is well within the range indicated by
13 my Second-Stage Retention Growth and Basic DCF analyses. This recommended
14 return reflects my assessment that Montana-Dakota's overall risks are
15 significantly higher than those of the proxy group.

16 **Q46. Does this conclude your Prepared Direct Testimony?**

17 A. Yes.

Montana-Dakota Utilities Co.

General Economic Statistics

1972-2002

Year	Percentage Price Changes		Real GDP Growth	Nominal GDP (Billions)
	Consumer Price Index	GDP Implicit Price Deflator		
1972	3.2%	4.3%	5.4%	1,240.4
1973	6.2%	5.6%	5.8%	1,385.5
1974	11.0%	9.0%	-0.6%	1,501.0
1975	9.1%	9.3%	-0.4%	1,635.2
1976	5.8%	5.7%	5.6%	1,823.9
1977	6.5%	6.4%	4.6%	2,031.4
1978	7.6%	7.1%	5.5%	2,295.9
1979	11.3%	8.3%	3.2%	2,566.4
1980	13.5%	9.2%	-0.2%	2,795.6
1981	10.3%	9.3%	2.5%	3,131.3
1982	6.2%	6.2%	-2.0%	3,259.2
1983	3.2%	4.0%	4.3%	3,534.9
1984	4.3%	3.7%	7.3%	3,932.7
1985	3.6%	3.1%	3.8%	4,213.0
1986	1.9%	2.2%	3.4%	4,452.9
1987	3.6%	3.0%	3.4%	4,742.5
1988	4.1%	3.4%	4.2%	5,108.3
1989	4.8%	3.8%	3.5%	5,489.1
1990	5.4%	3.9%	1.8%	5,803.2
1991	4.2%	3.6%	-0.5%	5,986.2
1992	3.0%	2.4%	3.0%	6,318.9
1993	3.0%	2.4%	2.7%	6,642.3
1994	2.6%	2.1%	4.0%	7,054.3
1995	2.8%	2.2%	2.7%	7,400.5
1996	3.0%	1.9%	3.6%	7,813.2
1997	2.3%	1.9%	4.4%	8,318.4
1998	1.6%	1.2%	4.3%	8,781.5
1999	2.2%	1.4%	4.1%	9,274.3
2000	3.4%	2.1%	3.8%	9,824.6
2001	2.8%	2.4%	0.3%	10,082.2
2002	1.6%	1.1%	2.4%	10,446.2
Average Rate of Change: 1/				
1972-2002	5.0%	4.3%	3.1%	7.4%
1982-2002	3.3%	2.8%	3.1%	6.0%
1992-2002	2.6%	1.9%	3.2%	5.2%

1/ Nominal GDP growth rates are based on the geometric average rate of change in nominal GDP.

Source: *Economic Report of the President*, February 2003 and
Economic Indicators, March 2003.

Montana-Dakota Utilities Co.

Mergent Bond Yield Averages *January 2002 - December 2003*

		Average Corporate	Public Utility Bonds	
			A-Rated	Baa-Rated
2002	JAN	7.38	7.66	8.13
	FEB	7.32	7.54	8.18
	MAR	7.57	7.76	8.32
	APR	7.49	7.57	8.26
	MAY	7.49	7.52	8.33
	JUN	7.36	7.42	8.26
	JUL	7.27	7.31	8.07
	AUG	7.06	7.17	7.74
	SEP	6.87	7.08	7.62
	OCT	7.07	7.23	7.99
	NOV	7.01	7.14	7.76
	DEC	6.90	7.07	7.61
2003	JAN	6.84	7.06	7.47
	FEB	6.62	6.93	7.17
	MAR	6.53	6.79	7.05
	APR	6.44	6.64	6.94
	MAY	6.02	6.36	6.47
	JUN	5.85	6.21	6.30
	JUL	6.26	6.57	6.67
	AUG	6.57	6.78	7.08
	SEP	6.37	6.56	6.87
	OCT	6.32	6.43	6.79
	NOV	6.27	6.37	6.69
	DEC	6.20	6.27	6.61

Source: Mergent Bond Record.

Montana-Dakota Utilities Co.

Average Return on Book Value of Equity for S&P 500 Companies

	Average Return on Equity	5-Year Moving Average ROE
2000	23.17	21.47
1999	23.49	20.69
1998	18.50	19.77
1997	20.89	18.99
1996	21.30	17.33
1995	19.27	15.12
1994	18.90	14.10
1993	14.57	13.43
1992	12.60	13.88
1991	10.25	13.97
1990	14.20	14.20
1989	15.53	13.70
1988	16.81	13.31
1987	13.05	12.35
1986	11.43	11.99
1985	11.67	12.51
1984	13.59	13.07
1983	12.00	13.50
1982	11.24	13.99
1981	14.04	14.50
1980	14.46	
1979	15.76	
1978	14.45	
1977	13.77	

Source: Standard & Poor's Analyst Handbook, 2001.

Montana-Dakota Utilities Co.

POPULATION IN NORTH DAKOTA COUNTIES WHERE MONTANA-DAKOTA PROVIDES NATURAL GAS SERVICE 1980 TO 2000

	1980	1990	2000	Population Change	
				1990-2000	1980-2000
North Dakota	652,717	638,800	642,200	0.05%	-0.08%
<u>Counties</u>					
Adams	3,584	3,174	2,593	-2.00%	-1.61%
Barnes	13,960	12,545	11,775	-0.63%	-0.85%
Benson	7,944	7,198	6,964	-0.33%	-0.66%
Billings	1,138	1,108	888	-2.19%	-1.23%
Bowman	4,229	3,596	3,242	-1.03%	-1.32%
Burke	3,822	3,002	2,242	-2.88%	-2.63%
Burleigh	54,811	60,131	69,416	1.45%	1.19%
Cavalier	7,636	6,064	4,831	-2.25%	-2.26%
Dunn	4,627	4,005	3,600	-1.06%	-1.25%
Eddy	3,554	2,951	2,757	-0.68%	-1.26%
Emmons	5,877	4,830	4,331	-1.08%	-1.51%
Foster	4,611	3,983	3,759	-0.58%	-1.02%
Golden Valley	2,391	2,108	1,924	-0.91%	-1.08%
Hettinger	4,275	3,445	2,715	-2.35%	-2.24%
Kidder	3,833	3,332	2,753	-1.89%	-1.64%
McKenzie	7,132	6,383	5,737	-1.06%	-1.08%
McLean	12,383	10,457	9,311	-1.15%	-1.42%
Morton	25,177	23,700	25,303	0.66%	0.02%
Mountrail	7,679	7,021	6,631	-0.57%	-0.73%
Pembina	10,399	9,238	8,585	-0.73%	-0.95%
Ramsey	13,048	12,681	12,066	-0.50%	-0.39%
Slope	1,157	907	767	-1.66%	-2.03%
Stark	23,697	22,832	22,636	-0.09%	-0.23%
Stutsman	24,154	22,241	21,908	-0.15%	-0.49%
Walsh	15,371	13,840	12,389	-1.10%	-1.07%
Ward	58,392	57,921	58,795	0.15%	0.03%
Williams	22,237	21,129	19,761	-0.67%	-0.59%
Total MDU	347,118	329,822	327,679	-0.07%	-0.29%

Montana-Dakota Utilities Co.**Moody's Natural Gas Distribution Companies
Fiscal Year 2003 Operating Data**

	<u>Assets</u> (\$000,000)	<u>Operating</u> <u>Revenues</u> (\$000,000)	<u>Operating</u> <u>Income</u> (\$000,000)
AGL Resources, Inc.	\$3,697	\$869	\$217 <u>1/</u>
Atmos Energy Corp.	\$2,519	\$2,800	\$190 <u>2/</u>
Energen Corporation	\$1,568	\$677	\$135 <u>1/</u>
KeySpan Corp.	\$13,000	\$5,971	\$935 <u>1/</u>
New Jersey Resources Corp.	\$1,571	\$2,544	\$122 <u>2/</u>
NICOR, Inc.	\$3,071	\$1,897	\$230 <u>1/</u>
Northwest Natural Gas Co.	\$1,326	\$641	\$101 <u>1/</u>
Piedmont Natural Gas Co., Inc.	\$1,511	\$1,221	\$147 <u>3/</u>
South Jersey Industries, Inc.	\$1,024	\$506	\$70 <u>1/</u>
WGL Holdings, Inc.	\$2,436	\$2,064	\$229
High	<u>\$13,000</u>	<u>\$5,971</u>	<u>\$935</u>
Median	<u>\$2,004</u>	<u>\$1,559</u>	<u>\$169</u>
Low	<u>\$1,024</u>	<u>\$506</u>	<u>\$70</u>
Montana-Dakota Gas Distribution*	\$183	\$255	\$4
MDU Resources Group, Inc.	\$2,623	\$2,224	\$273
<u>Montana-Dakota Gas Distribution % of:</u>			
- Proxy Company Median	9.1%	16.4%	2.4%
- MDU Resources Group, Inc.	7.0%	11.5%	1.5%

*Also includes results for Great Plains Natural Gas Co.

1/ Data as of 12/31/02.

2/ Data as of 09/30/03.

3/ Data as of 10/31/03.

Sources: Zacks.com; Annual Reports and 10-K's.

Montana-Dakota Utilities Co.

Bond Ratings of Selected Natural Gas Distribution Companies

	Standard & Poor's	Moody's
AGL Resources, Inc.	A-	A3
Atmos Energy Corp.	A-	A3
Energen Corporation	A-	A1
KeySpan Corp.	A+	A2
New Jersey Resources Corp.	AA-	Aa3
NICOR, Inc.	AA	Aa3
Northwest Natural Gas Co. **	A	A2
Piedmont Natural Gas Co., Inc.	A	A3
South Jersey Industries, Inc.	A	Baa1
WGL Holdings, Inc.	AA-	A2
Median	A	A2
MDU Resources Group, Inc.	A-	A2

Source: C.A. Turner, *Utility Reports*, January 2003

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies Dividend Yields July 2003 - December 2003

	Stock Price July '03 - December '03			Dividend	Yield
	High	Low	Average		
AGL Resources, Inc.	\$ 29.35	\$ 25.35	\$ 27.35	\$ 1.12	4.10%
Atmos Energy Corp.	\$ 25.50	\$ 23.00	\$ 24.25	\$ 1.22	5.03%
Energen Corporation	\$ 42.00	\$ 31.35	\$ 36.68	\$ 0.74	2.02%
KeySpan Corp.	\$ 37.09	\$ 32.30	\$ 34.70	\$ 1.78	5.13%
New Jersey Resources Corp.	\$ 39.54	\$ 33.70	\$ 36.62	\$ 1.30	3.55%
NICOR, Inc.	\$ 37.70	\$ 32.03	\$ 34.87	\$ 1.86	5.33%
Northwest Natural Gas Co.	\$ 31.30	\$ 27.02	\$ 29.16	\$ 1.30	4.46%
Piedmont Natural Gas Co., Inc.	\$ 43.95	\$ 37.23	\$ 40.59	\$ 1.66	4.09%
South Jersey Industries, Inc.	\$ 40.70	\$ 36.60	\$ 38.65	\$ 1.62	4.19%
WGL Holdings, Inc.	\$ 28.55	\$ 25.21	\$ 26.88	\$ 1.28	4.76%
Average					4.27%

Sources: America Online, January 29, 2003 and S&P Stock Guide, January, 2004.

Montana-Dakota Utilities Co.

Projected Earnings Retention Growth Rates for Selected Natural Gas Distribution Companies

	<u>Value Line Forecast 2006-2008</u>			Retention	Retention
	<u>EPS</u>	<u>DPS</u>	<u>ROE</u>	<u>Rate</u>	<u>Growth</u>
AGL Resources, Inc.	\$ 2.25	\$ 1.12	11.50%	50.22%	5.78%
Atmos Energy Corp.	\$ 2.00	\$ 1.32	12.50%	34.00%	4.25%
Energen Corporation	\$ 3.85	\$ 0.81	17.00%	78.96%	13.42%
KeySpan Corp.	\$ 3.30	\$ 1.90	12.00%	42.42%	5.09%
New Jersey Resources Corp.	\$ 3.10	\$ 1.40	12.50%	54.84%	6.85%
NICOR, Inc.	\$ 3.05	\$ 2.10	16.50%	31.15%	5.14%
Northwest Natural Gas Co.	\$ 2.35	\$ 1.37	10.00%	41.70%	4.17%
Piedmont Natural Gas Co., Inc.	\$ 3.05	\$ 1.90	11.50%	37.70%	4.34%
South Jersey Industries, Inc.	\$ 3.30	\$ 1.77	11.50%	46.36%	5.33%
WGL Holdings, Inc.	\$ 2.05	\$ 1.33	11.00%	35.12%	3.86%
Average					5.82%

Source: *Value Line*, Dec. 19, 2003.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth Rate Estimates for Selected Natural Gas Distribution Companies

		^{2/3} Zacks 5-Yr Earnings <u>Growth Est.</u>	^{1/3} Retention <u>Growth</u>	<u>Weighted Average</u>
AGL Resources, Inc.	ATG	5.20%	5.8%	5.39%
Atmos Energy Corp.	ATO	6.00%	4.3%	5.42%
Energen Corporation	EGN	8.30%	13.4%	10.01%
KeySpan Corp.	KSE	5.50%	5.1%	5.36%
New Jersey Resources Corp.	NJR	6.30%	6.9%	6.48%
NICOR, Inc.	GAS	4.30%	5.1%	4.58%
Northwest Natural Gas Co.	NWN	4.20%	4.2%	4.19%
Piedmont Natural Gas Co., Inc.	PNY	5.50%	4.3%	5.11%
South Jersey Industries, Inc.	SJI	6.30%	5.3%	5.98%
WGL Holdings, Inc.	WGL	3.90%	3.9%	3.89%
Average		5.55%	5.82%	5.64%

Source: Zacks.com and page 4.

Montana-Dakota Utilities Co.

**Second-Stage Retention Growth DCF Calculation
 for Selected Natural Gas Distribution Companies**

	Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Investor Required Return	Flotation Cost Adjustment	Cost of Capital
AGL Resources, Inc.	4.10%	4.23%	5.39%	9.62%	1.0475	10.08%
Atmos Energy Corp.	5.03%	5.20%	5.42%	10.62%	1.0475	11.12%
Energen Corporation	2.02%	2.14%	10.01%	12.15%	1.0475	12.73%
KeySpan Corp.	5.13%	5.30%	5.36%	10.67%	1.0475	11.17%
New Jersey Resources Corp.	3.55%	3.69%	6.48%	10.18%	1.0475	10.66%
NICOR, Inc.	5.33%	5.49%	4.58%	10.07%	1.0475	10.55%
Northwest Natural Gas Co.	4.46%	4.57%	4.19%	8.76%	1.0475	9.18%
Piedmont Natural Gas Co., Inc.	4.09%	4.22%	5.11%	9.33%	1.0475	9.78%
South Jersey Industries, Inc.	4.19%	4.35%	5.98%	10.33%	1.0475	10.82%
WGL Holdings, Inc.	4.76%	4.88%	3.89%	8.77%	1.0475	9.18%
Average						10.53%
High				12.15%		12.73%
Median				10.12%		10.60%
Low				8.76%		9.18%

Montana-Dakota Utilities Co.**Basic DCF Calculation
for Selected Natural Gas Distribution Companies**

	Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Investor Required Return	Flotation Cost Adjustment	Cost of Capital
AGL Resources, Inc.	4.10%	4.23%	5.20%	9.43%	1.0475	9.88%
Atmos Energy Corp.	5.03%	5.22%	6.00%	11.22%	1.0475	11.75%
Energen Corporation	2.02%	2.12%	8.30%	10.42%	1.0475	10.92%
KeySpan Corp.	5.13%	5.31%	5.50%	10.81%	1.0475	11.32%
New Jersey Resources Corp.	3.55%	3.69%	6.30%	9.99%	1.0475	10.46%
NICOR, Inc.	5.33%	5.48%	4.30%	9.78%	1.0475	10.24%
Northwest Natural Gas Co.	4.46%	4.58%	4.20%	8.78%	1.0475	9.19%
Piedmont Natural Gas Co., Inc.	4.09%	4.23%	5.50%	9.73%	1.0475	10.19%
South Jersey Industries, Inc.	4.19%	4.36%	6.30%	10.66%	1.0475	11.16%
WGL Holdings, Inc.	4.76%	4.88%	3.90%	8.78%	1.0475	9.19%
Average						10.43%
High				11.22%		11.75%
Median				9.88%		10.35%
Low				8.78%		9.19%

Montana-Dakota Utilities Co.

**Primary DCF Analysis
 Computation of the Cost of Capital
 for Selected Natural Gas Distribution Companies**

Growth Rate Estimate (g)	<u>5.00%</u>	<u>6.50%</u>
Current Dividend Yield (D/P)	4.27%	4.27%
Quarterly Model Dividend Yield Factor (1 + .625 g)	<u>X 1.031</u>	<u>X 1.041</u>
DCF Dividend Yield Component (Y)	4.40%	4.44%
Investor Required Return (Y + g)	9.40%	10.94%
Flotation Cost Adjustment	<u>X 1.0475</u>	<u>X 1.0475</u>
Cost of Capital	9.85%	11.46%
Mid-Point		10.65%

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies Capital Structures

	Long-Term Debt (Millions)	%	Preferred Stock (Millions)	%	Common Equity (Millions)	%	Total Capital
AGL Resources, Inc.	\$ 945.5	45.44%	\$ 226.7	10.90%	\$ 908.5	43.66%	\$ 2,080.7
Atmos Energy Corp.	\$ 873.3	50.45%	-	0.00%	\$ 857.5	49.55%	\$ 1,730.8
Energen Corporation	\$ 523.0	43.26%	-	0.00%	\$ 685.9	56.74%	\$ 1,209.0
KeySpan Corp.	\$ 4,938.8	54.43%	\$ 83.7	0.92%	\$ 4,050.8	44.65%	\$ 9,073.3
New Jersey Resources Corp.	\$ 260.3	38.32%	-	0.00%	\$ 418.9	61.68%	\$ 679.3
NICOR, Inc.	\$ 396.7	34.96%	\$ 1.7	0.15%	\$ 736.2	64.89%	\$ 1,134.6
Northwest Natural Gas Co. *	\$ 485.9	48.86%	\$ 7.5	0.75%	\$ 501.1	50.39%	\$ 994.4
Piedmont Natural Gas Co., Inc.**	\$ 462.0	41.73%	-	0.00%	\$ 645.1	58.27%	\$ 1,107.1
South Jersey Industries, Inc.	\$ 337.0	56.70%	-	0.00%	\$ 257.3	43.30%	\$ 594.3
WGL Holdings, Inc.	\$ 648.7	43.39%	-	0.00%	\$ 846.4	56.61%	\$ 1,495.1
		44.42%		0.00%		53.50%	

Sources: Zacks.com.

*as of 06/30/03

**as of 10/31/03

Montana-Dakota Utilities Co.

Common Equity Flotation Costs of Natural Gas Distribution/Transmission Companies 1992-2002

Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
Bay State Gas Co.	3/13/1992	1,550,000	\$23.250	\$22.280	4.35%
El Paso Natural Gas Co.	5/12/1992	5,000,000	\$19.000	\$17.770	6.92%
New Jersey Resources Co.	9/15/1992	1,500,000	\$22.250	\$21.270	4.61%
Washington Energy Co.	9/29/1992	2,750,000	\$21.000	\$20.190	4.01%
Equitable Resources	9/22/1993	2,400,000	\$38.500	\$37.250	3.36%
Brooklyn Union Gas	9/29/1993	1,700,000	\$25.750	\$24.770	3.96%
S.E. Michigan Gas Enterprises	1/19/1994	650,000	\$20.500	\$19.620	4.49%
Connecticut Energy Corp.	3/3/1994	900,000	\$20.125	\$19.220	4.71%
Mobile Gas Service Corp.	9/14/1994	400,000	\$22.000	\$20.300	8.37%
Northwest Natural Gas	2/15/1995	1,000,000	\$29.750	\$28.590	4.06%
MCN Corp.	3/14/1995	5,000,000	\$17.875	\$17.210	3.86%
Piedmont Natural Gas	3/20/1995	1,500,000	\$20.000	\$19.140	4.49%
Laclede Gas	5/15/1995	1,550,000	\$19.000	\$18.120	4.86%
United Cities	6/8/1995	1,200,000	\$14.500	\$13.880	4.47%
Atlanta Gas Light	6/12/1995	1,300,000	\$33.625	\$32.510	3.43%
WICOR, INC.	12/5/1995	1,100,000	\$31.875	\$30.630	4.06%
Connecticut Natural Gas	6/5/1996	640,000	\$23.250	\$22.190	4.78%
Delta Natural Gas	7/15/1996	350,000	\$16.000	\$15.070	6.17%
Tejas Gas	7/22/1996	3,075,000	\$35.000	\$33.420	4.73%
KN Energy	7/31/1996	3,100,000	\$32.250	\$31.010	4.00%
Cascade Natural Gas	8/13/1996	1,350,000	\$15.250	\$14.450	5.54%
Energen	1/17/1997	1,500,000	\$29.500	\$28.390	3.91%
KCS Energy	1/29/1997	3,000,000	\$39.000	\$36.910	5.66%
Energen	9/18/1997	1,200,000	\$35.500	\$34.160	3.92%
COHO Energy, Inc.,	9/29/1997	8,585,000	\$10.500	\$9.870	6.38%
Fall River Gas Co.	10/30/1997	340,000	\$13.250	\$12.060	9.87%
Connecticut Energy Corp.	11/12/1997	900,000	\$24.250	\$23.170	4.66%
Roanoke Gas Co.	2/22/1998	166,000	\$20.000	\$18.668	7.13%
KN Energy	3/4/1998	11,000,000	\$52.000	\$49.902	4.20%
Enron Corp.	5/5/1998	15,000,000	\$50.000	\$48.466	3.17%
Washington Gas Light	12/12/1998	2,000,000	\$25.063	\$24.089	4.04%
Laclede Gas	5/5/1999	1,100,000	\$20.188	\$19.252	4.86%
Semco	6/12/2000	9,000,000	\$10.000	\$9.600	4.17%
WGL Holdings	6/26/2001	1,790,000	\$26.730	\$25.804	3.59%
Utilicorp	1/25/2002	11,000,000	\$23.000	\$22.252	3.36%
MDU Resources Group	11/29/2002	2,100,000	\$24.000	\$23.188	3.50%
Average 1992-2002					4.77%
Selected Flotation Costs for Cost of Equity					4.75%

Sources: EBASCO, *Analysis of Public Utility Financing* and *Public Utility Financing Tracker*

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-04-__

Direct Testimony
of
Craig A. Keller, CPA

1 Q. Would you please state your name, business address and position?

2 A. Yes. My name is Craig A. Keller and my business address is 400
3 North Fourth Street, Bismarck, North Dakota 58501. I am the Vice
4 President, Controller and Chief Accounting Officer (CAO) for Montana-
5 Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources
6 Group, Inc.

7 Q. Would you please describe your duties?

8 A. As Vice President, Controller and Chief Accounting Officer, I am
9 responsible for providing the overall direction and management of the
10 accounting, information systems, financial forecasting/planning,
11 procurement and purchasing functions, including the analysis and reporting
12 of all financial transactions for Montana-Dakota.

13 Q. Would you please outline your educational and professional background?

14 A. I graduated from the University of Mary with a Bachelor of Science
15 degree in Accounting and obtained a Masters degree in Business
16 Administration from the University of Montana. I am a certified public
17 accountant and a member of the AICPA and the North Dakota Society of
18 Certified Public Accountants. I was employed with Montana-Dakota in

1 1986 as an Internal Auditor and during my career with the company have
2 held positions of Income Tax Supervisor, Corporate Financial Planning
3 Manager, and General Accounting Manager.

4 Q. Have you testified in other proceedings before regulatory bodies?

5 A. Yes, I have presented testimony before the Public Service
6 Commission of North Dakota.

7 Q. Are you familiar with the territory served by Montana-Dakota and
8 the facilities of the Company utilized in providing gas service?

9 A. Yes, I am.

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

11 A. I am responsible for presenting Statement A, Statement B, and
12 Statement F.

13 Q. Would you describe Statement A, Statement B and Statement F?

14 A. Statement A, pages 1 and 2 show Montana-Dakota's balance
15 sheet as of December 31, 2002 and December 31, 2003. Statement B
16 consists of Montana-Dakota's income statement for the twelve months
17 ended December 31, 2003. These statements have been prepared from
18 the Company's books and records that are maintained in accordance with
19 the Federal Energy Regulatory Commission (FERC) Uniform System of
20 Accounts.

21 Statement F shows the gas utility capital structure of Montana-
22 Dakota for the twelve months ended December 31, 2003 and the
23 projected average capital structure for 2004 and 2005. Statement F

1 includes the associated costs of debt, preferred stock and common
2 equity. This capital structure and the associated costs serve as the basis
3 for the overall rate of return requested by Montana-Dakota in this rate
4 filing of 9.887%. The basis for the requested 11.50% return on common
5 equity contained within the overall requested rate of return is supported by
6 the testimony of Dr. J. Stephen Gaske.

7 Q. Were these statements and the data contained therein prepared by you or
8 under your supervision?

9 A. Yes, they were.

10 Q. Are they true to the best of your knowledge and belief?

11 A. Yes, they are.

12 Q. Would you please explain Statement F?

13 A. Pages 1 through 3 of Statement F summarize the actual average
14 gas utility capital structure at December 31, 2003 and the projected
15 average capital structure and the related utility costs of capital for 2004
16 and 2005. As shown on page 3, the components of the 2005 projected
17 overall annual rate of return, which are used by Ms. Mulkern to calculate
18 the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	3.708%
Preferred Stock	0.210%
Common Equity	5.969%
Required Rate of Return	9.887%

19

1 The debt costs reflected on Statement F, pages 1 through 3
2 represent the actual weighted embedded costs of the long-term debt at
3 December 31, 2003 and that projected to be outstanding at December 31,
4 2004 and December 31, 2005 and are supported by Statement F,
5 Schedule F-1. In calculating the debt costs the "Yield-to-Maturity" method
6 (also referred to as the Internal Rate of Return ("IRR") method) is used to
7 determine the total cost for each respective debt issue as presented on
8 Schedule F-1, page 4 of 7. The yield-to-maturity calculation of each debt
9 issue outstanding gives consideration to the stated rates of interest being
10 paid on such debt, the timing of the interest payments, related issuance
11 expenses, underwriters' commissions and indenture revision costs, the
12 discount or premium realized upon issuance and the amortization of
13 losses on bond redemption transactions. This is the same method
14 Montana-Dakota has used to calculate long term debt costs in previous
15 proceedings before this Commission.

16 Statement F, Schedule F-2, supports the cost of Montana-Dakota's
17 preferred stock capital, representing the weighted cost of the issues at
18 December 31, 2003 and projected to be outstanding at December 31,
19 2004 and December 31, 2005.

20 Statement F, Schedule F-3, supports the Company's average utility
21 common equity balance at December 31, 2003, and the projected
22 average balances for 2004 and 2005.

23 Q. What does Statement F, Schedule F-1 show?

24 A. Page 1 is a summary showing the Company's long-term debt at
25 December 31, 2003 and average cost of debt. Page 2 shows the
26 projected average long-term debt and costs for 2004 and page 3 shows

1 the same information for projected 2005. Page 4 shows the cost and the
2 debt balance by issue at December 31, 2003.

3 Q. How did you derive the projected cost of debt for 2004 and 2005?

4 A. The projected cost of debt for 2004 and 2005 is based upon the
5 yield to maturity of each debt issue outstanding.

6 Q. Would you please describe Statement F, Schedule F-1, pages 5 through
7 7 and explain the amortization method utilized?

8 A. Pages 5 through 7 reflect the detail by issue of the annual
9 amortization of net discounts (losses) on advance purchases of debt that
10 are necessary to meet sinking fund requirements. For this proceeding,
11 the amortization has been computed on a straight-line basis over the
12 remaining life of the issues, the same calculation as is used by the
13 Company for accounting purposes.

14 Q. What does Statement F, Schedule F-2 show?

15 A. Pages 1 through 3 present the preferred stock balances at
16 December 31, 2003 and the projected average balances for 2004 and
17 2005. The anticipated weighted average cost of preferred stock is also
18 shown. Page 4 sets forth the various preferred stock issues outstanding
19 at December 31, 2003.

20 Q. What does Statement F, Schedule F-3 show?

21 A. Pages 1 through 3 present the common equity balances at
22 December 31, 2003 and the projected average balances for 2004 and
23 2005 including the projected changes in the balances each year.

24 Q. What does Statement F, Schedule F-4 show?

25 A. Schedule F-4 indicates that, during the five-year period preceding
26 December 31, 2003, MDU Resources Group, Inc. issued 37.9 million

1 additional shares of common stock in connection with a three-for-two
2 stock split. Also during that period, the number of authorized shares of
3 common stock was increased from 75 million at a par value of \$3.33 to
4 150 million with a par value of \$1.00.

5 Q. Would you please describe Statement F, Schedule F-5?

6 A. This schedule presents various financial and market data relative to
7 the Company's common stock for the years 1999 through 2003, and for
8 each month of the twelve month period ended December 31, 2003.

9 Q. Would you please describe Statement F, Schedule F-6?

10 A. This schedule shows that there was no reacquisition activity for
11 bonds and provides a summary of scheduled retirements of preferred
12 stock for the five years ended December 31, 2003.

13 Q. Does this conclude your direct testimony?

14 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-04-

Direct Testimony
of
Rita A. Mulkern

- 1 Q. Would you please state your name and business address?
- 2 A. Yes. My name is Rita A. Mulkern and my business address is 400
3 North Fourth Street, Bismarck, North Dakota 58501.
- 4 Q. What is your position with Montana-Dakota Utilities Co.?
- 5 A. I am the Regulatory Analysis Manager of Montana-Dakota Utilities
6 Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.
- 7 A. Would you please describe your duties as Regulatory Analysis Manager?
- 8 A. I am responsible for the preparation of cost of service studies, fuel
9 cost adjustments, purchased gas cost adjustments and gas tracking
10 adjustments in each of the jurisdictions in which Montana-Dakota
11 operates.
- 12 Q. Would you please describe your education and professional background?
- 13 A. I graduated from North Dakota State University in 1981 with a
14 Bachelor of Arts degree with majors in Economics and Business
15 Administration and a minor in Statistics. I joined Montana-Dakota in July
16 1981 as a Regulatory Statistician, became Cost of Service Supervisor in
17 1986 and assumed my current position in 1999.
- 18 Q. Have you testified in other proceedings before regulatory bodies?

1 A. Yes, I have presented testimony before the Public Service
2 Commissions of Montana, North Dakota, and Wyoming and Public Utilities
3 Commissions of Minnesota and South Dakota.

4 Q. Are you familiar with the territory served by Montana-Dakota and the
5 facilities of the Company utilized in providing gas service?

6 A. Yes, I am.

7 Q. Are you familiar with the books and records of Montana-Dakota and the
8 manner in which they are kept?

9 A. Yes. Montana-Dakota's books and records are kept in accordance
10 with the Federal Energy Regulatory Commission (FERC) Uniform System
11 of Accounts.

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

13 A. The purpose of my testimony is to present the per books cost of
14 service for the twelve months ended December 31, 2003, the projected
15 cost of service for 2004 and 2005, the calculation of the revenue
16 deficiency and the calculation of the interim request.

17 Q. What statements, schedules and exhibits are you sponsoring?

18 A. I am sponsoring Statements C through E, Statements G through L,
19 Statements N and O and Exhibit No.__(RAM-1) and Exhibit
20 No.__(RAM-2).

21 Q. Were these statements and exhibits prepared by you or under your direct
22 supervision?

23 A. Yes, they were.

24 Q. What were the results of North Dakota gas operations for 2003?

1 A. Statement L, pages 1 and 2 show the per books income statement
2 and rate base for total Company and North Dakota gas operations for
3 2003. The details for each line item, i.e. sales revenue, other revenue,
4 plant in service, etc., are included in the applicable Statement listed.

5 Q. How was the per books cost of service allocated to North Dakota?

6 A. The Company utilizes a jurisdictional accounting system that
7 directly assigns and/or allocates every item of revenue, expense and rate
8 base to the jurisdictions as part of the regular accounting process on a
9 monthly basis, resulting in jurisdictional results on an ongoing basis. The
10 allocation methods and procedures are the same as have previously been
11 adopted by this Commission and are based on the principle of assigning
12 and/or allocating costs to the cost causer. The total Company and North
13 Dakota information included in the Statements is from the books and
14 records of the Company.

15 Q. What test period are you using to determine the revenue requirement?

16 A. The revenue requirement is based on a projected average 2005
17 test year. Since final rates will become effective in late 2004, an average
18 2005 cost of service will best match the cost and customer levels at the
19 time that the rates will go into effect. The final rates from this proceeding
20 will be in effect for 2005 and the closer that revenues, expenses and rate
21 base reflect levels to be experienced in 2005, the better the match will be
22 and the better opportunity Montana-Dakota will have to earn its authorized
23 return. Montana-Dakota is using a future test year in accordance with
24 North Dakota Century Code §49-05-04.1.

1 Q. Would you describe the development of the projected cost of service for
2 2004 and 2005?

3 A. The projected 2004 and 2005 cost of service is presented in
4 Statement N, which contains all of the schedules supporting the income
5 statement on page 1, and Statement O, which contains all of the
6 schedules supporting the rate base on page 1. The revenues and
7 expenses reflect the annual level that will be experienced when the new
8 rates become effective. Likewise, the rate base reflects average 2004 and
9 2005 plant and related balances.

10 Q. Would you describe the development of the projected revenues and
11 expenses contained in Statement N?

12 A. Sales and transportation revenues are shown on page 2 and reflect
13 projected sales and transportation volumes for all classes. The projected
14 residential and firm general service sales volumes for 2004 and 2005 were
15 based on actual historical data and forecasted for 2004 and 2005. The
16 forecasted volumes reflect the projected growth in the number of firm
17 customers at approximately 1.0 percent per year along with continuing
18 conservation of 1.0% per year. The projected firm revenues were
19 calculated based on the projected volumes and number of customers
20 using the currently effective rates inclusive of the PGA effective February
21 1, 2004, exclusive of the surcharge adjustment and margin sharing
22 adjustment.

1 The sales and transportation volumes for the U.S. Air Force, small
2 interruptible and large interruptible classes were projected on a customer-
3 by-customer basis and the revenues were calculated using current rates.

4 Miscellaneous revenues, shown on page 3, are projected to remain
5 at the 2003 level.

6 Q. Would you describe the development of the operation and maintenance
7 expenses?

8 A. Yes. Pages 4 through 7 of Statement N summarize the projected
9 2004 and 2005 operation and maintenance (O&M) expenses, with the
10 details provided on pages 8 through 30. The cost of gas, shown on page
11 8, uses the projected sales volumes, adjusted for losses, and current gas
12 costs effective February 1, 2004.

13 Q. How were other O&M expenses projected for 2004 and 2005?

14 A. The Company's 2004 budget provided the basis for most of the
15 O&M expense items by individual resources, such as labor, benefits,
16 insurance, etc. Each resource was reviewed and projected for 2004 and
17 2005.

18 Q. Would you describe the development of the projected other O&M?

19 A. Yes. Labor expense is shown on page 9, with actual labor expense
20 for the twelve months ended December 31, 2003 as the starting point.
21 The labor expense for 2004 and 2005 was developed by applying the
22 projected percentage increase in total Company labor costs to the 2003
23 per books North Dakota labor expense. Projected total Company labor
24 costs were based on the labor amounts budgeted for 2004, with bonuses

1 adjusted to reflect a three year average, and results in a 6.82 percent
2 increase for 2004. A labor increase of 5.35% was applied to the 2004
3 labor expense to arrive at the 2005 labor expense.

4 Benefits expense consists of medical/dental insurance, pension
5 expense, the Supplemental Income Security Plan (SISP), 401K, post-
6 retirement, workers compensation and other benefits. Each of these
7 items, excluding the other benefits, was projected individually for 2004
8 using the 2004 budgeted amounts and applying the projected increase
9 from 2004 to each type of benefit. The benefits expense for 2005 was
10 calculated by applying the projected increase by type of benefit. Mr. Paul
11 W. Conley discusses the inclusion of the SISP expense in his testimony.

12 Insurance expense, as shown on page 11, reflects the current
13 insurance level for 2004, which is an 11.62 percent decrease from the
14 2003 level and a projected 2.50% increase for 2005.

15 Contract labor and consulting expense was reviewed by function,
16 with distribution related expenses increasing 27.89 percent and the
17 customer accounting, sales and A&G functions decreasing by 11.05
18 percent in 2004 and all functions increasing 2.50 percent in 2005. The
19 increase in contract labor in the distribution function reflects the increase
20 in expense associated with the services performed by outside parties,
21 such as the costs of line locating, parking lot, and building and grounds
22 maintenance, with the decrease in the other functions related to expenses
23 incurred in 2003 that are not projected to recur in 2004 or 2005.

1 Materials, capital installation credits and reimbursements overall
2 decrease in 2004. Expenditures for materials were higher than normal in
3 2003 and reflect a decrease in 2004. Capital installation credits and
4 reimbursements, which are indirectly related to materials, are projected to
5 increase 4.18 percent and 18.87 percent, respectively in 2004. All these
6 items are projected to increase 2.50 percent in 2005.

7 Vehicles and work equipment expense is shown on page 14 and is
8 calculated based on the projected plant and the current depreciation rates
9 in Statement O. The depreciation expense on these items is not charged
10 to depreciation expense but rather is charged to a clearing account where
11 it is then charged to O&M expense as the vehicles or work equipment is
12 used.

13 Postage expense is projected to decrease 2.93 percent in 2004 due
14 to higher than normal expenses in 2003 and to increase 2.50 percent in
15 2005.

16 Telephone expense reflects a 0.35 percent increase in 2004 and
17 2.50 percent in 2005. There were some expense items incurred in 2003
18 that are not projected to occur in 2004, resulting in expense for 2004 that
19 is relatively flat.

20 Office Supplies show a decrease in 2004 of 14.66 percent and an
21 increase of 2.50 percent in 2005. There were some expenses in this
22 category in 2003 that are not projected to recur in 2004.

23 Company consumption is the expense for electric and natural gas
24 consumption in Company buildings. The electric component is projected

1 to increase 1.18 percent in 2004 and remain flat in 2005. The natural gas
2 component is expected to increase 14.92 percent in 2004 and remain flat
3 in 2005.

4 Uncollectible accounts are projected based on the five year
5 average of net write-offs to sales and transportation revenues applied to a
6 projected revenue, which results in an increase in uncollectible accounts
7 for 2004 and is projected to remain flat in 2005.

8 Computer rental reflects the addition of a new server for the
9 Company's geographic information system (GIS) in 2004 and the full
10 annual effect of the server in 2005.

11 Industry dues are listed on pages 21 and 22 and are projected for
12 2004 and 2005.

13 Advertising is shown on page 23. Promotional advertising has
14 been eliminated, pursuant to North Dakota Administrative Code (NDAC)
15 §69-09-01-29. The informational and institutional advertising are
16 projected to remain at the 2003 levels.

17 Page 24 reflects the inclusion of contributions to Energy Share of
18 North Dakota.

19 Rate case expense is shown on page 25. The projected 2004 and
20 2005 level incorporates the projected rate case expenses from this case,
21 along with the costs pertaining to Case No. PU-399-02-183 that were not
22 included in the current amortization, amortized over a three-year period.

1 Page 26 shows the North Dakota portion of expenses associated
2 with the cost of performing a depreciation study for the gas and common
3 property, amortized over a five year period.

4 Q. What other O&M expenses are included in Statement N?

5 The items adjusted individually above represent approximately 88
6 percent of total North Dakota gas O&M. The remaining items, which make
7 up approximately 12 percent of other O&M, are projected to remain flat in
8 2004 and increase 2.50 percent in 2005.

9 Q. Would you describe the calculation of depreciation expense?

10 A. Yes. Depreciation expense for projected 2004 and 2005 is shown
11 on page 30 and was calculated using projected plant in service and the
12 depreciation rates as authorized in Case No. PU-399-02-183 and derived
13 from a study by AUS Consultants. The authorized depreciation rates are
14 included in Statement I. The composite depreciation rates and calculation
15 are shown on Statement O, pages 5 and 6.

16 Q. Would you describe the calculation of taxes other than income?

17 A. Yes. Taxes other than income are shown on pages 31 through 34.
18 Ad valorem taxes were calculated using the projected 2004 and 2005
19 plant in service and applying the effective tax rates based on the 2003
20 ratio of ad valorem taxes to plant.

21 Payroll taxes projected for 2004 and 2005 follow labor expense.
22 The ratio of payroll taxes to labor expense for 2003 was calculated and
23 applied to the projected 2004 and 2005 labor expense to determine the

1 projected levels. All other taxes other than income were projected to
2 remain at the 2003 level.

3 Q. Would you describe the calculation of federal and state income taxes?

4 A. The current income tax calculation is shown on pages 35 through
5 37. Interest expense is calculated on the projected rate base using the
6 weighted cost of long term debt from Statement F. The tax deductions on
7 page 37 were individually projected. The tax rate of 39.55% reflects the
8 composite state and federal rate. Deferred income taxes are shown on
9 page 38 and include the full normalization of federal and state deferred
10 income taxes.

11 Q. Would you please describe the development of the projected rate base for
12 2004 and 2005?

13 A. Yes. The rate base was developed as shown in Statement O.
14 Page 1 shows the 2003 actual and projected 2004 and 2005 average rate
15 base for North Dakota gas operations. Pages 2 and 3 show the projected
16 plant in service for 2004 and 2005. The projected plant was developed by
17 adding the capital budget items for 2004 to the 2003 plant in service
18 balances. Retirements, based on a three-year average of retirements by
19 function, were deducted and the average 2004 balance calculated. The
20 process was repeated for 2005.

21 The accumulated reserve for depreciation was calculated using the
22 reserve balances at December 31, 2003, adding the calculated
23 depreciation expense and deducting retirements based on a three-year
24 average of retirements. The average 2004 balances were then calculated

1 and are shown on pages 4 through 6. The process was repeated to arrive
2 at the average 2005 reserve balances.

3 Q. How were the working capital items derived?

4 A. The projected working capital items are shown on pages 7 through
5 12. Materials and supplies were restated to a thirteen month average
6 balance on page 8 and the propane fuel stocks are restated to a thirteen
7 month balance on page 9.

8 Prepayments, made up of prepaid insurance and the prepaid tax-
9 free option plan, as shown on page 10, are also restated to a thirteen-
10 month average balance. Projected 2004 is based on the actual balances
11 as of December 31, 2003 and projected monthly levels based on the
12 projected insurance expense for 2004 and 2005.

13 The unamortized portion of the gas IRP and gas supply analysis
14 costs arising from the ten year amortization of the costs are restated to
15 reflect the current amortization and a thirteen month average and are
16 shown on page 11. These costs will be completely amortized in 2004.

17 Customer Advances for construction are restated to a thirteen
18 month balance as of December 2003.

19 The accumulated deferred income tax balances on page 13 were
20 derived by adding the deferred income taxes related to property for 2004
21 and 2005 to the 2003 balance from Statement N, page 31 and calculating
22 average balances.

1 The accumulated investment tax credit balances were derived by
2 subtracting the projected amortization for 2004 and 2005 from the 2003
3 balance and calculating average balances.

4 Q. What does Exhibit No.____(RAM-1) show?

5 A. Exhibit No.____(RAM-1), page 1, which is identical to Statement L,
6 page 4, shows the calculation of the revenue deficiency of \$3,337,000
7 based on the projected 2005 operating income and rate base and using
8 the overall rate of return of 9.887% from Statement F, page 1. Page 2
9 shows the per books and projected average rate base for 2004 and 2005
10 and is identical to Statement O, page 1.

11 Q. Is Montana-Dakota seeking an interim increase in this case?

12 A. Yes, it is. As stated by Mr. Imsdahl, Montana-Dakota is seeking
13 interim rate relief in this case pursuant to North Dakota §49-09-06.

14 Q. What does Exhibit No.____(RAM-2) show?

15 A. Exhibit No.____(RAM-2), which is identical to the Interim Revenue
16 Requirement, page 1, shows the calculation of the revenue deficiency of
17 \$1,871,000 based on the 2004 projected cost of service and adjusted for
18 items previously not allowed by the Commission. The revenue
19 requirement uses the projected 2004 capital structure and costs with the
20 exception of the return on equity, which is the return on equity last
21 authorized by this Commission in Case No. PU-399-02-183.

22 Q. Does that complete your testimony?

23 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - NORTH DAKOTA
PROJECTED 2005
(000s)

	Before Additional Revenue Re- quirements	Additional Revenue Requirements	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	\$119,307	\$3,337	\$122,644
Transportation	783		783
Other	406		406
Total Revenues	120,496	3,337	123,833
Operating Expenses			
Operation and Maintenance			
Cost of Gas	99,473		99,473
Other O&M	17,546		17,546
Total O&M	117,019		117,019
Depreciation	2,615		2,615
Taxes Other Than Income	1,421		1,421
Current Income Taxes	263	1,320	1,583
Deferred Income Taxes	(873)		(873)
Total Expenses	120,445	1,320	121,765
Operating Income	\$51	\$2,017	\$2,068
Rate Base	\$20,914		\$20,914
Rate of Return			
	0.244%		9.887%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - NORTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003
PROJECTED 2004-2005
(000s)

	2003	Projected	
		2004	2005
Gas Plant in Service	\$72,556	\$75,096	\$77,873
Accumulated Reserve for Depreciation	49,644	51,343	53,572
Net Gas Plant in Service	22,912	23,753	24,301
CWIP in Service Pending Reclassification	427		
Total Gas Plant in Service	23,339	23,753	24,301
Additions			
Materials and Supplies	393	475	475
Fuel Stock	25	22	22
Prepayments	50	181	190
Other	44	4	0
Total Additions	512	682	687
Total Before Deductions	\$23,851	\$24,435	\$24,988
Deductions			
Accumulated Deferred Income Taxes	\$3,909	\$3,845	\$3,674
Accumulated Investment Tax Credits	207	166	146
Customer Advances	297	254	254
Total Deductions	4,413	4,265	4,074
Total Rate Base	\$19,438	\$20,170	\$20,914

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
INTERIM
GAS UTILITY - NORTH DAKOTA
PROJECTED 2004
(000s)

	Before Additional Revenue Re- quirements	Additional Revenue Requirements	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	\$119,376	\$1,871	\$121,247
Transportation	783		783
Other	406		406
Total Revenues	<u>120,565</u>	<u>1,871</u>	<u>122,436</u>
Operating Expenses			
Operation and Maintenance			
Cost of Gas	99,630		99,630
Other O&M	16,299		16,299
Total O&M	<u>115,929</u>		<u>115,929</u>
Depreciation	2,537		2,537
Taxes Other Than Income	1,362		1,362
Current Income Taxes	516	740	1,256
Deferred Income Taxes	(620)		(620)
Total Expenses	<u>119,724</u>	<u>740</u>	<u>120,464</u>
Operating Income	<u>\$841</u>	<u>\$1,131</u>	<u>\$1,972</u>
Rate Base	<u>\$20,170</u>		<u>\$20,170</u>
Rate of Return			
	<u>4.170%</u>		<u>9.776% 1/</u>

**BEFORE THE
PUBLIC SERVICE COMMISSION OF NORTH DAKOTA**

IN THE Matter of the Notice of
Montana-Dakota Utilities Co.
for a Gas Rate Change

Case No. PU-399-04-_____

DIRECT TESTIMONY OF

PAUL W. CONLEY

ON BEHALF OF Montana-Dakota Utilities Co.

March 2004

**DIRECT TESTIMONY OF
PAUL W. CONLEY**

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Paul W. Conley. I am employed by Towers Perrin at 8000 Norman Center Drive, Suite 1200, Minneapolis, Minnesota 55437-1097.

Q. Please describe your education and professional background.

A. I am a Principal at Towers Perrin and am the leader of the Executive Compensation practice in Towers Perrin's Minneapolis office. I have been with Towers Perrin for eight years. I received an undergraduate degree from the St. John's University in Collegeville, Minnesota, and a Masters in Industrial Relations (MAIR) from the University of Minnesota. I am certified as a Certified Compensation Professional (CCP) by World at Work, and a Senior Practitioner in Human Resources (SPHR) by the Society for Human Resource Management. Before joining Towers Perrin, I was the Director of Executive Compensation for International Multifoods.

Q. Please provide a brief overview of Towers Perrin.

A. Towers Perrin is a global professional services firm that helps organizations around the world optimize performance through effective people, risk and financial management. The firm has approximately 8,000 employees in approximately 75 offices worldwide. Towers Perrin's compensation practice is one of the largest in the world. Towers Perrin has dedicated energy and utility industry practitioners specializing in compensation, human resources, benefits, and organization design.

Q. Please summarize the purpose of your testimony.

A. The purpose of my testimony is to comment on Towers Perrin's analysis of the competitiveness and appropriateness of MDU Resources Group Inc.'s

33 (MDU) Supplemental Employee Retirement Program (SERP) called the
34 Supplemental Income Security Plan (SISP), as part of its total executive
35 compensation program.

36

37 **THE SUPPLEMENTAL INCOME SECURITY PLAN**

38

39 **Q. What is the SISP and what is the plan designed to do?**

40 A. The SISP is a plan that provides a supplemental pension benefit to key
41 employees. It was designed to attract and retain key employees in a
42 number of positions within the Company and provide equitable retirement
43 benefits for those employees.

44

45 **Q. Who are the employees that participate in the SISP plan?**

46 A. Participants are officers and senior managers of MDU Resources and
47 Montana-Dakota. While all employees are important to MDU, these
48 participants are directly responsible for planning for the future, identifying
49 and implementing appropriate strategies for the Company, implementing
50 effective cost reduction programs, streamlining the organization,
51 implementing new technologies and maintaining and increasing the
52 efficiencies of the Company. These employees have the primary
53 management responsibility for keeping the Company competitive in the
54 industry and maintaining an adequate supply of low-cost energy for MDU's
55 customers.

56

57 **Q. What is the difference between a qualified pension plan and a
58 supplemental plan?**

59 A. A qualified pension plan is designed to provide a certain level of retirement
60 benefits to participants, generally based on replacing a certain amount of
61 income as the retirement benefit. These qualified plans are subject to IRS
62 limitations on both recognized pay and benefit payouts. As such, a
63 qualified pension plan cannot provide the full amount called for by its
64 formula to officers and senior managers subject to these limitations.

65 Supplemental plans help restore retirement benefits to their original
66 intended level, in order to ensure a competitive overall retirement program.

67

68 **Q. How prevalent are programs like the SISP in the utility industry and**
69 **more generally in the labor market for managerial talent?**

70 A. Among MDU's peer companies, we observed nearly 100% prevalence of
71 the provision of retirement benefits beyond those provided in the qualified
72 plan. This is also true for the broader labor market. Programs such as
73 these represent a normal cost of doing business.

74

75 **Q. Why are supplemental retirement plans so common?**

76 A. The retirement benefits normally provided in the qualified plan are limited
77 by IRS regulations (for those whose income exceeds the IRS limits), and
78 as such are not provided in the full amount called for in the qualified plan
79 design. Supplemental programs like the SISP help to restore the
80 retirement benefits to their intended level, as well as ensure a competitive
81 and appropriate overall retirement program. The removal of the SISP
82 program, like the removal of any other component of MDU's overall reward
83 program, would unduly hamper the company from meeting its overall
84 reward objectives.

85

86 **Q. How do the overall retirement benefits for employees included in the**
87 **SISP compare with the retirement benefits for those employees not**
88 **included in the SISP?**

89 A. As an employee moves up the income scale, the percentage of the
90 employee's preretirement income replaced by social security and qualified
91 retirement plans significantly decreases based on retirement plan design
92 requirements and government limitations on retirement plans. The SISP,
93 as a supplemental plan, has been designed to replace some, but not all, of
94 the income that is not replaced by Social Security, the Defined Benefit
95 Pension Plan, and the 401 (k) Plan. At the highest participating income
96 levels, less than 50 percent of the annual income is replaced through the

97 combination of social security, qualified plans, and the SISP as compared
98 to approximately 80 percent at lower income levels for those employees
99 not participating in SISP.

100

101 **COMPETITIVENESS OF MDU'S EXECUTIVE COMPENSATION PLAN**
102 **INCLUDING SISP**

103

104 **Q. How is MDU's executive compensation plan derived?**

105 A. The Compensation Committee of MDU's Board of Directors is responsible
106 for determining the compensation of the Company's executive officers.
107 The Committee is composed entirely of outside (or non-employee)
108 Directors who meet several times each year to review and determine
109 compensation for the executives. The Compensation Committee seeks to
110 set appropriate compensation levels that attract, motivate, and retain
111 high-quality employees. To implement this philosophy, the Committee
112 analyzes trends in compensation among comparable companies and
113 relies in part on information and recommendations by outside advisors and
114 data sources in making their decisions. MDU has retained Towers Perrin
115 to provide information, analysis and recommendations to assist the Board
116 of Directors in their decision making.

117

118 **Q. Without compromising the proprietary nature of the information**
119 **provided by Towers Perrin, could you describe in more detail the**
120 **scope of its review and the methods it uses?**

121 A. Yes. Towers Perrin annually provides a report to MDU that includes
122 competitive market data regarding compensation plans from hundreds of
123 companies throughout the region and nation that have similar types of
124 positions and responsibilities. This information is provided for MDU's
125 internal use only.

126 Towers Perrin also provides an updated analysis of MDU's executive
127 compensation programs. Specifically, Towers Perrin provides a current
128 market assessment of competitive pay levels for base salary, total annual

129 cash (base salary plus annual bonus) and total direct compensation (total
130 annual cash plus the expected value of long-term incentives) for all
131 identified management positions and a recommended updated salary
132 grade structure based on the above competitive analyses. In addition,
133 benefits data are reviewed periodically to ensure the competitiveness of
134 the overall rewards program.

135

136 **Q. When was a competitive assessment like this last conducted for**
137 **MDU?**

138 A. Towers Perrin last completed a review of the competitiveness of MDU's
139 compensation and benefits programs in the spring and summer of 2003.

140

141 **Q. What is the process Towers Perrin uses to conduct this analysis?**

142 A. Towers Perrin provides a consistent approach each year to ensure that the
143 comparative data are valid over time. This includes confirming positions to
144 be included in the analysis, identifying material changes to MDU's jobs, if
145 any, updating current compensation information, gathering and analyzing
146 relevant salary survey data, validating survey data, and summarizing and
147 reporting results.

148

149 **Q. Does Towers Perrin use only its own salary database?**

150 A. Towers Perrin considers data from both general industry and
151 industry-specific surveys. Competitive information was collected from the
152 following sources:

153 1) Towers Perrin's 2002 Energy Services Executive Compensation
154 Database, which is conducted in partnership with the Edison Electric
155 Institute (EEI). This source is the most comprehensive survey of
156 executive compensation for the U.S. electric and gas industry,
157 comprising data for 89 investor-owned utilities and public power
158 authorities.

159 2) Towers Perrin's 2002 Compensation Data Bank General Industry
160 Survey, which is one of the most reputable sources of data on

161 executive compensation in the U.S. It includes data on approximately
162 800 companies ranging in size from less than \$100 million in annual
163 sales to greater than \$10 billion.

164 3) Watson Wyatt's 2002 Industry Report on Top Management
165 Compensation, covering more than 2,000 organizations across the
166 U.S., ranging in size from less than \$10 million in annual sales to
167 greater than \$1 billion.

168 4) Effective Compensation Association, Inc.'s American Gas Association
169 2002 Executive Compensation Survey, comprising approximately 70
170 organizations with annual revenues ranging from less than \$10 million
171 in annual sales to greater than \$1 billion.

172 5) Hay Group's 2002 Natural Gas Transmission Survey, comprising 20
173 organizations with annual revenues ranging from approximately \$100
174 million to greater than \$5 billion.

175 6) Mercer HR Consulting's 2002 Energy Compensation Survey,
176 comprising approximately 120 organizations ranging in size from less
177 than \$100 million to greater than \$1 billion in annual revenues.

178 7) Towers Perrin's Employee Benefit Information Center (EBIC)
179 database, from which a custom cut of data on 16 organizations of
180 similar size and industry to MDU were gathered. These data were
181 utilized to compare MDU's benefits Program to these other
182 comparable organizations.

183 8) A study by Towers Perrin of the 2003 proxy filings from approximately
184 15 public companies similar to MDU in size and industry used to
185 assess prevalence and competitive levels of retirement benefits
186 including qualified and nonqualified retirement plans.

187

188 **Q. How does Towers Perrin use the information from the various**
189 **databases to establish market levels for its analysis of MDU's**
190 **executive compensation?**

191 A. Competitive data are gathered from the above databases based on a
192 number of criteria in order to estimate market levels for MDU. These

193 criteria include industry and size comparability, the degree of match
194 between the responsibility level of MDU's positions and those in the
195 databases, and reliability of the database results over time. Survey data
196 are blended to arrive at an overall market estimate for MDU.

197

198 **Q. How does the Compensation Committee of the Board of Directors**
199 **use the information it receives from Towers Perrin?**

200 A. When the Compensation Committee develops MDU's "Total
201 Compensation" plan, it focuses on the competitive salaries and benefits,
202 including the SISP, that are necessary to maintain its ability to attract,
203 retain, and appropriately reward the individuals needed to provide reliable,
204 safe, efficient, and cost effective service to MDU's customers. It should be
205 emphasized that in setting executive compensation, the Compensation
206 Committee looks at the total compensation picture, not just one element by
207 itself.

208

209 **Q. How does Towers Perrin define competitive compensation?**

210 A. Towers Perrin defines competitive compensation as generally falling
211 between plus or minus 10% of the market median (50th percentile).
212 Competitive data can vary from one year to the next; our goal is to help
213 MDU position its reward programs to approximate the middle of the market
214 in a stable fashion over time. The median (or 50th percentile) is used as a
215 statistic rather than average as a better representation of the middle-range
216 of competitive practice. Accordingly, half of the responding organizations
217 pay less than this amount, and half pay more than this amount. The mean
218 or average tends to be somewhat higher than the median, and can be
219 influenced more easily by outliers.

220

221 **Q. What are the typical components included in a company's total**
222 **compensation program for management-level employees?**

223 A. Companies normally provide the following elements as a cost of doing
224 business and as part of their overall program to attract, retain and motivate

225 management employees: base salaries, annual incentives, long-term
226 incentives, retirement benefits (including both qualified and nonqualified
227 plans), and health and welfare benefits. In addition, other important reward
228 elements normally provided are learning and development opportunities
229 and investments in the overall work environment. While these other
230 elements are important and often included in a definition of total rewards,
231 in this case we are focused primarily on traditional elements of
232 compensation and benefits since these elements represent the
233 overwhelming majority of a company's cost for reward programs.

234

235 **Q. Which elements are considered in Towers Perrin's competitive**
236 **evaluation of MDU's total rewards program?**

237 A. The elements included are base salary, annual incentives, long-term
238 incentives, retirement benefits (including qualified and nonqualified plans),
239 and health and welfare benefits.

240

241 **Q. What is MDU's competitive position for each of the elements that**
242 **Towers Perrin has assessed?**

243 A. Based on the results of the 2003 assessment by Towers Perrin (with
244 competitive data updated to be effective as of January 1, 2004), the
245 relative market position of each of the elements studied, based on the
246 competitive studies referenced above, is as follows:

247 For MDU's corporate and utility company executives, the overall base
248 salary competitive position is approximately 91% of the market 50th
249 percentile. For total annual cash compensation (base salary plus annual
250 bonus), the overall competitive position is approximately 99% of the
251 market 50th percentile. For total direct compensation, the overall
252 competitive position is approximately 107% of the market 50th percentile.

253 For the total benefits program (excluding the value of SERP benefits),
254 MDU corporate is at 100% of the market 50th percentile. The utility
255 company is 95% of the market 50th percentile. For the combined qualified
256 and nonqualified retirement benefit program (which includes the SISP for

257 MDU and SERPs provided by MDU's peers, and assuming a senior
258 manager with \$200,000 in final average pay (salary plus annual bonus)
259 and 30 years of service, MDU's retirement program is approximately 105%
260 of the market 50th percentile.

261

262 **Q. How does Towers Perrin therefore view the overall competitiveness**
263 **of MDU's compensation program?**

264 A. Towers Perrin considers an organization that is within plus or minus 10%
265 of the market 50th percentile to be within the competitive range. Given the
266 fact that most of MDU's program elements fall within plus or minus 5% of
267 the market 50th percentile, we find the overall program to be competitive
268 and appropriate. Therefore, the removal of any of these elements would
269 represent a competitive shortfall in MDU's ability to attract and retain
270 qualified executives.

271

272 **Q. Why is the SISP an important piece of MDU's total compensation**
273 **plan?**

274 A. MDU's total compensation package, including SISP, is currently within the
275 competitive range of plus or minus 10% of the market 50th percentile.
276 Removal of any piece of the total compensation package would reduce the
277 competitive position of MDU's compensation package. To remain within
278 the competitive range of the market's 50th percentile, MDU would
279 potentially be required to increase other elements of executive
280 compensation. Replacement of the SISP benefit with some alternative
281 form of compensation might actually result in increased costs to provide an
282 equivalent benefit level. SISP therefore is an important element of a
283 balanced and competitive compensation package for executive employees
284 who tend to be experienced employees who consider retirement benefits
285 an important part of a total compensation package.

286

287 **Q. Does this conclude your testimony?**

288 A. Yes.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-04-_____

Direct Testimony
of
Tamie A. Aberle

1 Q. Would you please state your name and business address?

2 A. Yes. My name is Tamie A. Aberle, and my business address is
3 400 North Fourth Street, Bismarck, North Dakota 58501.

4 Q. What is your position with Montana-Dakota Utilities Co.?

5 A. I am the Pricing & Tariff Manager in the Regulatory Affairs
6 Department of Montana-Dakota Utilities Co. (Montana-Dakota), a Division
7 of MDU Resources Group, Inc.

8 Q. What are your responsibilities as the Pricing & Tariff Manager?

9 A. My responsibilities include the preparation of rate design and
10 miscellaneous tariff revision filings to ensure that the applicable revenue
11 requirements are properly recovered from various customer classes via
12 applicable rate forms. I also administer utility tariffs and rules and regula-
13 tions effective in each of the jurisdictions in which Montana-Dakota
14 provides utility service.

15 Q. Would you please outline your educational and professional background?

16 A. I graduated from Moorhead State University, Moorhead, Minnesota
17 in 1982 with a Bachelor of Science degree in Accounting. I began my
18 career with Montana-Dakota in 1983 in the Regulatory Affairs Department,
19 I was promoted to Rate Administration Supervisor in 1990 and achieved

1 my present position in May 1999.

2 Q. Have you testified in other proceedings before regulatory bodies?

3 A. Yes. I have previously presented testimony before this
4 Commission, the Public Service Commissions of Montana and Wyoming,
5 and the Public Utilities Commissions of Minnesota and South Dakota.

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

7 A. The purpose of my testimony is to present the results of the class
8 cost of service study and to address the effect of the proposed revenue
9 requirement, as identified by Ms. Mulkern in her direct testimony, on each
10 of the Company's gas rates, including how the distribution of the revenue
11 requirement was made among the various classes of customers served.
12 In addition, my testimony will discuss the extent to which Montana-Dakota
13 is proposing changes in rate design and/or tariff conditions.

14 Q. What statements and exhibits are you sponsoring in this proceeding?

15 A. I am sponsoring Statement M and Exhibit No. ____ (TAA-1) and
16 Exhibit No. ____ (TAA-2). I also sponsor the proposed rate schedules to
17 be effective on a final basis and the proposed rate schedules appended to
18 the Application for Interim Rate Relief.

19 Q. What is the total revenue effect of the proposed gas rate changes?

20 A. The proposed interim rates will produce additional revenues of
21 \$1,869,539 or 1.6% annually based on the interim level of test period
22 sales, while the final proposed rates will produce additional revenues of
23 \$3,334,226 or 2.8% annually based on projected throughput. Exhibit No.
24 ____ (TAA-1) represents summaries by rate classification of the proposed
25 interim and final revenue increase on pages 1 and 2 respectively. The
26 exhibit shows the rate number and a description along with the revenues

1 calculated under the present and proposed rates. The amount and
2 percentage increase is also shown for the proposed revenue increase.

3 Q. Would you please explain the embedded class cost of service study
4 contained in Statement M?

5 A. Yes. Turning to Statement M, Schedule M-1, the first report
6 appearing therein is entitled "Cost of Service by Component." This report
7 shows the total dollars and unit cost required under each rate if the overall
8 requested 9.887% rate of return was to be earned for the demand, energy
9 and customer cost components of each rate schedule.

10 The next report appearing on Statement M, Schedule M-1, page 4
11 is entitled "Summary." This report shows the results of all of the
12 succeeding reports in summary form. Following this summary report is a
13 detailed report showing the development of each line on the Summary
14 Report.

15 Statement M, Schedule M-2 entitled "Allocation Assignment
16 Report," is a report that shows how the various allocation factors and
17 items directly assigned were applied in producing the various reports
18 shown in Schedule M-1.

19 Statement M, Schedule M-3 entitled "Allocation Factor Report," is
20 simply a list of the allocation factors used to produce the various reports
21 shown in Schedule M-1. By using the Allocation Assignment Report and
22 the Allocation Factor Report, it can be readily determined how the various
23 components of revenue, expense, and plant were allocated or assigned
24 among the classes of service.

25 The class cost of service study is based on the results for North
26 Dakota gas operations recorded for the 12 months ended December 31,

1 2003 as adjusted to reflect the Projected 2005 test period underlying the
2 total cost of service in this case.

3 Q. What were the results of the cost of service study?

4 A. The results for the Projected 2005 test year are summarized on
5 Statement M, Schedule M-1, page 4. The overall North Dakota gas rate
6 of return based on the projected 2005 overall cost of service is .24%. The
7 returns by customer class are as shown below:

8	Residential Service	(3.26)%
9	Firm General Service	2.69 %
10	Air Force	27.12 %
11	Small Interruptible	18.91 %
12	Large Interruptible	39.26 %

13 Q. For what purpose has the class cost of service study been used?

14 A. The study results have been used as a guide in the distribution of
15 total revenue requirements among customers and for the purpose of
16 pricing the various components comprising the total rate applicable to
17 each customer class.

18 Q. What methodology did you use to apportion the proposed rate increase
19 among the customer classes?

20 A. In designing the proposed rates to reflect the additional revenue
21 requirements, I have attempted to group the class rates of return more
22 closely about the overall system return.

23 Given the disparity between the firm and interruptible class
24 contributions to the overall return, the proposed increase was allocated to
25 the Residential and Firm General Service classes only.

26 Q. How was the proposed interim revenue requirement apportioned among

1 the customer classes?

2 A. The interim revenue increase of \$1,871,000 was applied to the
3 rate classes on a equal percentage basis to the Residential and Firm
4 General Service classes which is consistent with the revenue allocations
5 authorized in Case No. PU-399-02-183. The Distribution Delivery Charge
6 was increased while the Basic Service Charge amounts remain the same
7 as authorized in Case No. PU-399-02-183. The rate design calculations
8 supporting the interim rate levels are included in Appendix B attached to
9 the Application for Interim Increase in Natural Gas Rates.

10 Q. What is the percentage of the proposed interim and final increase by class
11 of customer?

12 A. As shown on Exhibit No. ____ (TAA-1), the proposed interim and
13 final increase to each of the classes is shown in the table below:

14 **Table 1 - % Increase in Revenues**

<u>Class</u>	<u>Interim</u>	<u>Final</u>
Residential	1.7%	3.5%
Firm General Service	1.7%	2.3%
Air Force	0.0%	0.0%
Small Interruptible	0.0%	0.0%
Large Interruptible	<u>0.0%</u>	<u>0.0%</u>
Overall	1.6%	2.8%

15 Q. What is the effect of the proposed final revenue increase on the class
16 returns?

17 A. The revenue allocation, on a final basis, results in an increase in
18 the residential class return from (3.26)% to 7.75% and an increase in the
19 firm general service class return from 2.69% to 11.35%.

20 Q. How are you proposing to collect the allocated final increase from the
21 Residential and Firm General Service classes?

1 A. First, I am proposing modest increases to the Basic Service
2 Charges applicable under each of the firm service rate schedules. The
3 Basic Service Charge under Residential Rate 60 has been set at \$0.30
4 per day which reflects an average monthly charge of \$9.12, an increase of
5 \$.30 per month from the currently effective charge. The Basic Service
6 Charge applicable to Firm General Service customers with meters rated
7 less than 500 cubic feet per hour has been set at \$0.52 per day and \$1.75
8 per day for customers requiring the larger meters capable of measuring
9 gas flows of 500 cubic feet per hour or greater. The resulting average
10 monthly charges will be \$15.81 and \$53.20 respectively representing an
11 increase of \$.61 per month in the Basic Service Charge applicable to
12 customers using meters rated less than 500 cubic feet per hour and an
13 increase of \$1.52 per month in the Basic Service Charge for customers
14 requiring meters rated at 500 cubic feet per hour or higher.

15 The remaining increase in revenues, after taking into account the
16 revenue increase associated with the changes in the Basic Service
17 Charge, will be collected through the applicable Distribution Delivery
18 Charge components.

19 Q. Would you please explain Exhibit No. ____ (TAA-2)?

20 A. Yes. Exhibit No. ____ (TAA-2) depicts bill comparisons based on
21 typical monthly consumption levels for an annual period for residential and
22 firm general service customers. As shown by the comparisons, the
23 proposed rate structure will result in an average increase of approximately

1 \$2.62 per month for the typical Residential customer using 110 dk on an
2 annual basis.

3 Q. Would you please explain the Distribution Delivery Stabilization
4 Mechanism tariff you are proposing as part of this rate case?

5 A. Yes. A Distribution Delivery Stabilization Mechanism (DDSM) is
6 being proposed as a means of adjusting customers' bills to reflect normal
7 weather. The proposed DDSM Rate 87 tariff specifies the procedure to
8 be utilized to correct for the over/under collection of distribution delivery
9 charge revenues due to weather fluctuations during the heating season,
10 defined as November 1 through March 31. The DDSM will provide a
11 better matching, with regard to volumes used in the case to determine the
12 charge per dk necessary to recover the authorized distribution costs and
13 the collection of distribution revenues. Because the volumes used to
14 calculate the distribution delivery charge are based on volumes expected
15 under normal weather conditions, the Company will either over collect
16 distribution revenues if weather is colder than normal or under collect
17 distribution revenues if weather is warmer than normal. As described in
18 the proposed tariff (Rate 87), A DDSM will be determined for each rate
19 schedule subject to the DDSM and shall be expressed as rate per dk.
20 Monthly bills beginning with the first billing cycle following May 1, 2005
21 and each May 1st thereafter, will be adjusted (decreased or increased) by
22 the application of a DDSM rate computed in accordance with the
23 procedures based on temperature conditions for the winter heating

1 season beginning November 1, 2004 ending March 31, 2005, and each
2 heating season thereafter, compared to normal temperature levels
3 established in the most recent general rate case. The DDSM rate will be
4 stated as a surcharge or credit on all rate schedules to which the DDSM is
5 applicable. A DDSM rate will be computed for each applicable rate
6 schedule to be effective for a period of one year. Following the initial one-
7 year term, and annually thereafter, the DDSM rate calculation will include
8 any over or under collection of DDSM revenue from the preceding twelve-
9 month recovery period. If weather is colder than normal the DDSM will be
10 a credit adjustment and reduce customers' bills. If weather is warmer
11 than normal the DDSM will be a positive adjustment and increase
12 customers' bills.

13 Q. Would you please briefly describe other changes made to the Company's
14 gas tariff?

15 A. Yes, following is a description of other changes the Company is
16 proposing to make to its gas tariff:

- 17 • A provision regarding standby service has been added to the
18 Residential and Firm General Service rate schedules. As
19 noted, natural gas service provided by Montana-Dakota is not to
20 be used as a standby fuel source. Customers who do so are
21 not adequately contributing toward fixed cost recovery because
22 a substantial portion of the Company's fixed distribution costs
23 are recovered through the Distribution Delivery Charge and

1 therefore dependent upon a customer actually using natural gas
2 volumes. In other words, customers utilizing natural gas service
3 as a standby energy source are causing increased peak
4 demand without the typical annual consumption associated with
5 a heating customer. The proposed standby charge of \$8.00 per
6 month for residential customers and \$15.00 per month for firm
7 general service customers was designed to recover the fixed
8 customer and distribution demand related costs not recovered
9 through the Basic Service Charge. Any larger Firm General
10 Service customer, defined as a customer using a meter rated
11 greater than 500 cubic feet per hour, will be charged an amount
12 for applicable pipeline demand and storage costs based on the
13 customer's potential maximum daily demand, in addition to the
14 monthly fixed charge of \$15.00.

15 • In the last case (PU-399-02-183) the reconnection fees for
16 customers that reconnect service at the same location where
17 service was disconnected by the same customer during the
18 preceding 12-month period was tied to the Basic Service
19 Charge that would have been applied during the period the
20 customer was out of service. As a refinement to that process,
21 the Company is proposing to provide seasonal business
22 concerns such as irrigation, grain drying and asphalt processing
23 a credit for distribution revenues contributed during the time in

1 service in order to recognize that while not connected for a full
2 12-month period, the seasonal business customers typically use
3 volumes of gas equal to or greater than a typical firm general
4 service customer although in a shorter time frame. Given a
5 substantial portion of the company's fixed costs are recovered
6 through the distribution delivery or commodity charge it is
7 appropriate to recognize volumes used when determining the
8 appropriate reconnection charge for the seasonal business
9 customer.

- 10 • Minor changes which are self explanatory have been made to
11 the majority of the rate schedules. These changes are clearly
12 denoted on the tariff sheets reflecting the legislative format.

13 Q. Does this conclude your direct testimony?

14 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - NORTH DAKOTA
Proposed Interim Rates

Customer Class/Rate	Customers	Projected 2004		Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase	Increase per Dk
		Dk	Revenue					
Residential - Rate 60	74,149	8,150,298	\$66,710,124	\$67,834,865	\$1,124,741	1.7%	\$0.138	
Firm General Service - Rate 70	11,470	5,773,626	44,197,944	44,942,742	744,798	1.7%	0.129	
Air Force - Rate 64								
Firm	1	37,297	252,218	252,218	0	0.0%	0.000	
Interruptible	2	842,568	4,734,108	4,734,108	0	0.0%	0.000	
Total Air Force	3	879,865	4,986,326	4,986,326	0	0.0%	0.000	
Small Interruptible								
Sales - Rate 71	82	570,263	3,481,200	3,481,200	0	0.0%	0.000	
Transport - Rate 81	57	703,084	401,449	401,449	0	0.0%	0.000	
Total Small Interruptible	139	1,273,347	3,882,649	3,882,649	0	0.0%	0.000	
Large Interruptible								
Sales - Rate 85	0	0	0	0	0	0.0%	0.000	
Transport - Rate 82	10	2,229,392	381,588	381,588	0	0.0%	0.000	
Total Large Interruptible	10	2,229,392	381,588	381,588	0	0.0%	0.000	
Total North Dakota	85,771	18,306,528	\$120,158,631	\$122,028,170	\$1,869,539	1.6%		

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - NORTH DAKOTA
Proposed Final Rates

Customer Class/Rate	Projected 2005		Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
	Customers	Dk				
Residential - Rate 60	74,919	8,152,728	\$66,809,177	\$69,145,273	\$2,336,096	3.5%
Firm General Service - Rate 70	11,532	5,747,216	44,030,409	45,028,539	998,130	2.3%
Air Force - Rate 64						
Firm	1	37,297	252,218	252,218	0	0.0%
Interruptible	2	842,568	4,734,108	4,734,108	0	0.0%
Total Air Force	3	879,865	4,986,326	4,986,326	0	0.0%
Small Interruptible						
Sales - Rate 71	82	570,263	3,481,200	3,481,200	0	0.0%
Transport - Rate 81	57	703,084	401,449	401,449	0	0.0%
Total Small Interruptible	139	1,273,347	3,882,649	3,882,649	0	0.0%
Large Interruptible						
Sales - Rate 85	0	0	0	0	0	0.0%
Transport - Rate 82	10	2,229,392	381,588	381,588	0	0.0%
Total Large Interruptible	10	2,229,392	381,588	381,588	0	0.0%
Total North Dakota	86,603	18,282,548	\$120,090,149	\$123,424,375	\$3,334,226	2.8%

**MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 RATE 60 BILL COMPARISON
 RESIDENTIAL GAS SERVICE**

<u>Month</u>	<u>Dk</u>	<u>Present Rate</u>	<u>Proposed Rate</u>	<u>Amount of Increase</u>	<u>% Increase</u>
January	19	\$147.58	\$152.69	\$5.11	3.46%
February	14	110.24	114.06	3.82	3.47%
March	14	111.11	114.96	3.85	3.47%
April	9	74.35	76.92	2.57	3.46%
May	6	52.75	54.58	1.83	3.47%
June	3	30.58	31.64	1.06	3.47%
July	2	23.58	24.39	0.81	3.44%
August	2	23.58	24.39	0.81	3.44%
September	4	37.88	39.19	1.31	3.46%
October	8	67.34	69.68	2.34	3.47%
November	12	96.23	99.56	3.33	3.46%
December	17	132.99	137.60	4.61	3.47%
Total	110	\$908.21	\$939.66	\$31.45	3.46%

Average Increase per Month \$2.62

<u>RATE 60</u>	<u>Current 1/</u>	<u>Proposed 2/</u>
Basic Delivery Charge	\$0.29	\$0.30
Distribution Delivery	\$0.641	\$0.894
Cost of Gas	6.653	\$6.653

1/ Rate effective February 1, 2004
 2/ Includes February 2004 cost of gas.

**MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 RATE 70 BILL COMPARISON
 FIRM GENERAL GAS SERVICE (< 500 Cubic Feet Per Hour Meters)**

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	51	\$378.93	\$387.35	\$8.42	2.22%
February	39	291.91	298.44	6.53	2.24%
March	39	293.41	300.00	6.59	2.25%
April	24	186.02	190.30	4.28	2.30%
May	15	122.39	125.31	2.92	2.39%
June	9	79.13	81.11	1.98	2.50%
July	6	58.26	59.79	1.53	2.63%
August	6	58.26	59.79	1.53	2.63%
September	12	100.51	102.95	2.44	2.43%
October	21	165.15	168.98	3.83	2.32%
November	33	250.16	255.81	5.65	2.26%
December	45	336.17	343.68	7.51	2.23%
Total	300	\$2,320.30	\$2,373.51	\$53.21	2.29%

RATE 70	Current 1/	Proposed 2/
Basic Delivery Charge	\$0.50	\$0.52
Distribution Delivery	\$0.473	\$0.626
Cost of Gas	6.653	\$6.653

1/ Rate effective February 1, 2004

2/ Includes February 2004 cost of gas.

**MONTANA-DAKOTA UTILITIES CO.
 GAS UTILITY - NORTH DAKOTA
 RATE 70 BILL COMPARISON
 FIRM GENERAL GAS SERVICE (> 500 Cubic Feet Per Hour Meters)**

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	153	\$1,142.98	\$1,167.94	\$24.96	2.18%
February	117	881.34	900.64	19.30	2.19%
March	117	886.44	905.89	19.45	2.19%
April	72	564.07	576.59	12.52	2.22%
May	45	373.37	381.81	8.44	2.26%
June	27	243.40	249.03	5.63	2.31%
July	18	180.97	185.27	4.30	2.38%
August	18	180.97	185.27	4.30	2.38%
September	36	307.54	314.54	7.00	2.28%
October	63	501.64	512.83	11.19	2.23%
November	99	756.47	773.12	16.65	2.20%
December	135	1,014.71	1,036.92	22.21	2.19%
Total	900	\$7,033.90	\$7,189.85	\$155.95	2.22%

RATE 70	Current 1/	Proposed 2/
Basic Delivery Charge	\$1.70	\$1.75
Distribution Delivery	\$0.473	\$0.626
Cost of Gas	6.653	\$6.653

1/ Rate effective February 1, 2004
 2/ Includes February 2004 cost of gas.