KC|DJ|MT|KS|MB

NG04-004

DOCKET NO.

NGU4-004

In the Matter of IN THE MATTER OF THE FILING BY MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE

Public Utilities Commission of the State of South Dakota

DATE		MEMORANDA
6/7	04	Filed and Docketed;
6/10	04	Weekly Filing;
6/30	04	Order of Assessment of Filing Fee and Suspension of Imposition of Tariff;
7/27	04	Order Correcting Date of Suspension of Imposition of Tariff;
8/16	04	Contract between Chesapeake and the SDPUC;
8/26	04	Order for and Notice of Procedural Schedule and Hearing;
10/4	04	Amended Order for and Notice of Procedural Schedule and Hearing;
10/15	04	Testimony of Michelle M. Farris and Basil L. Copeland, Jr.;
10/18	04	Testimony of Martin C. Bettmann;
10/19	04	Testimony of David A. Jackson, Keith A. Senger and Robert D. Towers;
10/28	04	Order Cancelling Hearing;
11/15	04	Joint Motion for Approval of Settlement Stipulation;
11/15	04	Settlement Stipulation;
11/17	04	Revised Tariff Pages;
11/18	04	Staff Memorandum Supporting Settlement Stipulation;
12/10	04	Order Granting Joint Motion for Approval of Settlement Stipulation;
12/10	04	Docket Closed.

STATE PUBLISHING CO., PIERRE, SOUTH DAKOTA—SMEAD 62 SP14130

NG04-004

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG04-____
APPLICATION

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 South Dakota

NG04-004

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

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

RECEIVED
JUN 07 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

June 4, 2004

Ms. Pamela Bonrud
Executive Director
South Dakota Public Utilities
Commission
State Capitol Building
500 East Capitol
Pierre, SD 57501

Re: General Natural Gas Rate Application
Docket No. NG04-___

Dear Ms. Bonrud:

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits its application for approval to increase its rates for natural gas service. This application does not affect the rates applicable to those customers receiving natural gas service in Montana-Dakota's East River service area.

Montana-Dakota encloses herein an Original and ten (10) copies of this Letter of Transmittal, Application with Appendices A and B, Testimony and Exhibits and supporting Statements that document the need for this request to increase rates for natural gas service. This filing is made in accordance with Administrative Rules of South Dakota (ARSD), Sections 20:10:13:26 and 20:10:13:39 through 20:10:13:104 inclusive.

The Company's need for additional revenues results from increases in operating and maintenance expenses driven largely by increases in labor, benefits costs, and depreciation expense. In spite of cost control efforts, increases in operating and maintenance expense have caused current rates to be inadequate in compensating the Company for operating its South Dakota (excluding East River service area) natural gas distribution system.

Montana-Dakota's last general rate increase in South Dakota was implemented in 2003 as authorized in Docket NG02-011.

Montana-Dakota proposes a total annual increase of $1,281,417 or 2.2%, based on a 2003 test year adjusted for known and measurable changes. The proposed change in rates will affect customer classes as follows: Residential, 2.9%, Firm General Service, 2.0% and Large Interruptible Service, 1.0%. The proposed increase for a residential customer will average about $1.96 per month or about $23.51 per year.

The proposed rate changes do not affect the recovery of the cost of purchased gas, which is separately reflected in retail rates (and recovered monthly) through the Purchased Gas Cost Adjustment.

Included in Appendix B of the Application is a second set of the affected tariffs on which Montana-Dakota has indicated the revisions requested by lining through the existing language, which the Company proposes to delete, and underlining the new proposed language.

In accordance with ARSD 20:10:13:39(6), it is noted that the proposed rates may potentially affect 43,100 gas customers located in the Company's Black Hills service area in South Dakota. Attached as Exhibit A is the South Dakota "Report of Tariff Schedule Change" form required pursuant to ARSD 20:10:13:26.

The Company will comply with ARSD 20:10:13:18 by posting a Notice of the proposed rates, as shown on Exhibit B, in each of its business offices in its Black Hills gas service territory affected by the proposed change.

Please refer all inquiries regarding this filing to:

Mr. Donald R. Ball
Assistant Vice President-
Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501

Also, please send copies of all written inquiries, correspondence and pleading to:

Mr. Douglas W. Schulz Associate General Counsel & Assistant Secretary MDU Resources Group, Inc. P. O. Box 5650 Bismarck, ND 58506-5650	David A. Gerdes May, Adam, Gerdes & Thompson 503 South Pierre Street P.O. Box 160 Pierre, South Dakota 57501-0160

Montana-Dakota respectfully requests that this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R. Ball

Donald R. Ball
Assistant Vice President-
Regulatory Affairs

Attachments
cc: D.W. Schulz
D.A. Gerdes

Exhibit A

Report of Tariff Schedule Change

NAME OF UTILITY: Montana-Dakota Utilities Co.
ADDRESS: 400 North Fourth Street
Bismarck, ND 58501

Section No.	Class of Service	New Sheet No.
1	Table of Contents	1st Revised Sheet Nos. 1-1.1
3	Residential Rate 60	1st Revised Sheet No. 2
3	Firm General Service Rate 70	1st Revised Sheet No. 11
3	Optional Seasonal General Gas Service Rate 72	1st Revised Sheet No. 13
3	Transporation Service Rates 81 and 82	1st Revised Sheet No. 22.1
3	Large Interruptible General Gas Service Rate 85	1st Revised Sheet No. 26
5	General Provisions Rate 100	1st Revised Sheet Nos. 1-1.19
5	Service Lines Rate 124	1st Revised Sheet No. 24
6	Sample Forms	1st Rev Sheet Nos. 5,8,8.1,12, 13 & 16

Change: Rates, applicability, and availability
(State part of tariff schedule affected by change, such as: Applicability, availability, rates, etc.)

Reason for Change: To enable Company to earn an adequate return on its investment.

Present Rates $58,064,657
Proposed Rates $59,346,074
Approximate annual reduction in revenue .....
Approximate annual increase in revenue ..... $ 1,281,417

Points Affected	Estimated Number of Customers Whose Cost of Service will be:					
	Reduced		Increased		Unchanged	
Black Hills System	# of Customers	Amount in $	# of Customers	Amount in $	# of Customers	Amount in $
	NONE		43,100	$1,281,417		

Include Statement of Facts, expert opinions, documents and exhibits supporting the change requested.

Received: _____

Montana-Dakota Utilities Co.
(Reporting Utility)

By: _____
Executive Director
South Dakota
Public Utilities Commission

By: Donald R. Ball
Assistant Vice President -
Regulatory Affairs

SD-20:10:13:26

On June 7, 2004, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., filed with the South Dakota Public Utilities Commission revised gas rates affecting Montana-Dakota Utilities Co.'s gas customers in South Dakota. These proposed rates, and South Dakota rules and regulations, are available in this office for inspection. Please inquire at the cashier's desk.

Exhibit B

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Natural Gas Service	)))))	Docket No. NG04-__

* * * *

APPLICATION

COMES NOW, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., the Applicant in the above-entitled proceeding (hereafter "Montana-Dakota" or "Applicant"), and respectfully alleges as follows:

I.

That Montana-Dakota, a Division of MDU Resources Group, Inc., is a Delaware corporation duly authorized to do business in the State of South Dakota as a foreign corporation, and that it is doing business in the State of South Dakota as a public utility.

II.

That the Certificate of Incorporation and Amendments thereto have previously been filed with the South Dakota Public Utilities Commission (PUC or Commission) and reference thereto is hereby made, and such Certificate and Amendments are hereby incorporated herein by reference as though fully set forth herein.

III.

That Applicant's full name and post office address are:

Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, North Dakota 58501

IV.

That the following described rate schedules presently on file with and approved by the Commission are attached hereto as Appendix A.

Section 1	
Original Sheet Nos. 1-1.1	Table of Contents
Section 2	
Original Sheet Nos. 1-1.1	Preliminary Statement
Section 3	
5th Revised Sheet No. 1	Rate Summary Sheet
Original Sheet No. 2	Residential Gas Service Rate 60
Original Sheet Nos. 5-5.1	Ellsworth Air Force Base Rate 64
Original Sheet No. 7	East River Natural Gas System General Services Rate 66
Original Sheet Nos. 11-11.1	Firm General Gas Service Rate 70
Original Sheet Nos. 12-12.2	Small Interruptible General Gas Service Rate 71
Original Sheet Nos. 13-13.1	Optional Seasonal General Gas Service Rate 72
Original Sheet Nos. 22-22.8	Transportation Service Rates 81, 82
Original Sheet Nos. 26-26.2	Large Interruptible General Gas Service Rate 85
Original Sheet Nos. 28-28.1	Distribution Delivery Stabilization Mechanism
Original Sheet Nos. 29-29.5	Purchased Gas Cost Adjustment Rate 88
Original Sheet Nos. 30-30.5	East River Natural Gas System Purchased Gas Cost Adjustment Rate 89

Section 4

1st Revised Sheet No. 1	List of Gas Contracts with Deviations

Section 5

Original Sheet Nos. 1-1.19	General Provisions Rate 100
Original Sheet No. 3	Rate for Residential Gas Service for Regular Employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc. and Wholly-Owned Subsidiaries of MDU Resources Group, Inc. Rate 102
Original Sheet Nos. 19-19.1	Interruptible Gas Service Extension Policy Rate 119
Original Sheet Nos. 20-20.5	Firm Gas Service Extension Policy Rate 120
Original Sheet No. 24	New Installation, Replacement, Relocation and Repair of Gas Service Lines Rate 124
Original Sheet No. 34-34.3	Rule and Policies for Implementing Master Metering Restrictions Rate 134

Section 6

Original Sheet No. 1	Consumer's Deposit Receipt
Original Sheet No. 2	New Customer Application Card
Original Sheet No. 3	Gas Meter Order
Original Sheet Nos. 4-4.1	Standard Customer Bill Form
Original Sheet No. 5	Disconnect Notice
Original Sheet No. 6	Application for Interruptible Natural Gas Service
1st Revised Sheet Nos. 7-7.1	Customer Information Booklet
Original Sheet No. 8	Discontinuance Notice for Unauthorized Use of Service
Original Sheet No. 9	Third Party Notice
Original Sheet No. 10	Deferred Installment Agreement Form
Original Sheet No. 11	Agreement by Property Owner or Agent to Pay Utility Bills During Periods When Property is Unoccupied
Original Sheet No. 12	Forms Advising Property Owner Tenant is Vacating Premises and Service has been Connected in Property Owner's Name Per an Agreement
Original Sheet No. 13	Guarantee of Payment for Natural Gas and/or Electric Service by a Second Party in Lieu of a Deposit
Original Sheet No. 14	Deposit Warning Letter
Original Sheet No. 15	Deposit Request

Original Sheet No. 16	Final Notice Prior to Disconnect
Original Sheet Nos. 17-17.3	Interruptible General Gas Service Agreement
Original Sheet No. 18	Request for Firm Natural Gas Sales Service
Original Sheet Nos. 19-19.7	Gas Transportation Agreement
Original Sheet Nos. 20-20.1	Customers Agreement for Gas Extension
Original Sheet Nos. 21-21.1	Gas Service Order
Original Sheet No. 22	Facilities Relocation Agreement
Original Sheet No. 23	Warning Notice
Original Sheet No. 24	Temporary Construction Heat Agreement

V.

That Applicant respectfully submits herewith the following described proposed rate schedules for gas service, copies attached hereto as Appendix B, which Applicant proposes to substitute for the corresponding rate schedules described in the preceding paragraph.

Section 1

1st Revised Sheet Nos. 1-1.1	Table of Contents

Section 3

To be submitted on final disposition of the rate application	Rate Summary Sheet
1st Revised Sheet No. 2	Residential Gas Service Rate 60
1st Revised Sheet No. 11	Firm General Gas Service Rate 70
1st Revised Sheet No. 13	Optional Seasonal General Gas Service Rate 72
1st Revised Sheet No. 22.1	Transportation Service Rates 81 and 82
1st Revised Sheet No. 26	Large Interruptible General Gas Service Rate 85

Section 5

1st Revised Sheet Nos. 1-1.19	General Provisions Rate 100
1st Revised Sheet No. 24	New Installation, Replacement, Relocation and Repair of Gas Service Lines Rate 124

Section 6

1st Revised Sheet No. 5	Disconnect Notice
1st Revised Sheet Nos. 8-8.1	Discontinuance Notices for Unauthorized Use of Service & Discontinuance for Reasons Other than Nonpayment
1st Revised Sheet No. 12	Reserved for Future Use
1st Revised Sheet No. 13	Guarantee of Payment for Natural Gas and/or Electric Service by a Second Party in Lieu of a Deposit
1st Revised Sheet No. 16	Final Notice Prior to Disconnect

VI.

That the existing rates of Applicant are unjust, unreasonable and not compensatory, and that said rates should be increased so that Applicant will have an opportunity to earn a just and reasonable rate of return on its natural gas property devoted to providing service to its South Dakota natural gas customers.

VII.

That in submitting this Application and in proposing the implementation of the increased rates contained herein, Applicant is seeking additional revenues before income taxes of $1,281,417 based on a 2003 test year adjusted for known and measurable changes, for natural gas service rendered to customers located in the Black Hills service territory in the State of South Dakota. This Application does not affect the rates applicable to those customers receiving natural gas service in Montana-Dakota's East River service area.

VIII.

That Applicant will prove by competent evidence that existing rates are unjust, unreasonable, and not compensatory, and that said rate schedules should be increased as requested herein. Filed concurrently with this Application and its Appendices are supporting Statements and direct testimony and exhibits of Applicant's witnesses. Said Statements, Testimony and Exhibits are by this reference incorporated as if fully set forth herein.

IX.

That this Application is submitted in accordance with the provisions of South Dakota Codified Laws, Chapter 49-34A and the rules and regulations promulgated by the Public Utilities Commission of the State of South Dakota.

WHEREFORE, Applicant respectfully requests that the Public Utilities Commission of the State of South Dakota:

1. Approve and adopt the proposed rate changes as set forth in Appendix B of this Application to be effective upon final disposition of this docket;
2. Expedite any hearing which the Commission deems necessary to determine the propriety of Applicant's proposed rate schedules set forth herein, and issue its final order establishing the rates set forth herein; and
3. Grant such other and additional relief as the Commission shall deem just and proper.

Dated this 4th day of June 2004.

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

By: Donald R. Ball

Donald R. Ball
Assistant Vice President -
Regulatory Affairs

STATE OF NORTH DAKOTA)
:ss
COUNTY OF BURLEIGH)

Donald R. Ball, being first duly sworn, deposes and says that he is the Assistant Vice President - Regulatory Affairs of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., the Applicant herein, that he has read the foregoing Application, knows the contents thereof, and that the same is true and correct to the best of his knowledge, information and belief.

Dated this 4th day of June 2004.

Donald R. Ball
Assistant Vice President –
Regulatory Affairs

Subscribed and sworn to before me this 4th day of June 2004.

MARY BRANDT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires MAR. 9, 2005

Mary Brandt, Notary Public
Burleigh County, North Dakota
My Commission Expires: 3/9/05

OF COUNSEL:

David A. Gerdes
May, Adam, Gerdes & Thompson
503 South Pierre Street
P.O. Box 160
Pierre, South Dakota 57501-0160

Douglas W. Schulz
Associate General Counsel & Assistant Secretary
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 1
Original Sheet No. 1
Canceling Vol. 1 15th Rev. Sheet No. 1

TABLE OF CONTENTS

Designation	Title	Sheet No.
Section No. 1	Table of Contents	1
Section No. 2	Preliminary Statement	1
Section No. 3	Rate Schedules	
	Rate Summary Sheet	1
Rate 60	Residential Gas Service	2
	Reserved for Future Use	3-4
Rate 64	Ellsworth Air Force Base	5
	Reserved for Future Use	6
Rate 66	East River Natural Gas System General Services	7
	Reserved for Future Use	8-10
Rate 70	Firm General Gas Service	11
Rate 71	Small Interruptible General Gas Service	12
Rate 72	Optional Seasonal General Gas Service	13
	Reserved for Future Use	14-21
Rate 81 and 82	Transportation Service	22
	Reserved for Future Use	23-25
Rate 85	Large Interruptible General Gas Service	26
	Reserved for Future Use	27
Rate 87	Distribution Delivery Stabilization Mechanism	28
Rate 88	Purchased Gas Cost Adjustment	29
Rate 89	East River Natural Gas System Purchase Gas Cost Adjustment	30
Section No. 4	List of Contracts with Deviations	1
Section No. 5	Rules	
Rate 100	General Provisions	1
	Reserved for Future Use	2
Rate 102	Residential Rate for Regular Employees	3
	Reserved for Future Use	4-18
Rate 119	Interruptible Gas Service Extension Policy	19
Rate 120	Firm Gas Service Extension Policy	20
	Reserved for Future Use	21-23

Date Filed: December 30, 2002
Effective Date: Service Rendered on and after December 2, 2003
Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs
Implemented
December 4, 2003
Docket No.: NG02-011

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TABLE OF CONTENTS

Rate 124	New Installation, Replacement, Relocation and Repair of Gas Service Lines	24
	Reserved for Future Use	25-33
Rate 134	Rules and Policies for Implementing Master Metering Restrictions	34
Section No. 6	Sample Forms	
	Consumer's Deposit Receipt	1
	New Customer Application Card	2
	Gas Meter Order	3
	Standard Customer Bill	4
	Disconnect Notice	5
	Application for Interruptible Natural Gas Service	6
	Customer Information Booklet	7
	Discontinuance Notice for Unauthorized Use of Service	8
	Third Party Notice	9
	Deferred Installment Agreement Form	10
	Agreement by Property Owner or Agent to Pay Utility Bills During Periods When Property is Unoccupied	11
	Form Advising Property Owner Tenant is Vacating Premises and Service Has Been Connected in Property Owner's Name per an Agreement	12
	Guarantee of Payment for Natural Gas and/or Electric Service by a Second Party in Lieu of a Deposit	13
	Deposit Warning Letter	14
	Deposit Request	15
	Final Notice Prior to Disconnect	16
	Interruptible General Gas Service Agreement	17
	Request for Firm Natural Gas Sales Service	18
	Gas Transportation Agreement	19
	Customers Agreement for Gas Extension	20
	Gas Service Order	21
	Facilities Relocation Agreement	22
	Warning Notice	23
	Temporary Construction Heat Agreement	24

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

PRELIMINARY STATEMENT

PRELIMINARY STATEMENT
*Designates Region Office

Montana-Dakota Utilities Co. serves twenty-six (26) towns and their environs in eleven (11) counties in South Dakota with natural gas. Counties served are:

Butte	Lawrence	Stanley
Edmunds	Meade	Sully
Harding	Pennington	Walworth
Hughes	Potter	

Communities served under Rate 66 are designated (66), all other communities are served under the otherwise applicable rates.

Bismarck Region

Bowdle (66)	Glenham (66)	Roscoe (66)
Gettysburg (66)	Ipswich (66)	Selby (66)
Mobridge (66)		

Rapid City Region

Agar (66)	Deadwood	Pluma
Belle Fourche	Lead	*Rapid City
Black Hawk	Onida (66)	St. Onge
Box Elder	Piedmont	Spearfish
Camp Crook	Ft. Pierre (66)	Sturgis
Central City	Pierre (66)	Terraville
		Whitewood

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

PRELIMINARY STATEMENT

TYPES AND CLASSES OF SERVICES

The Company will furnish natural gas service for existing residential and small commercial customers. Where economically feasible the Company will extend its service lines to new customers if the Company's gas supply is adequate.

The following symbols shall be used in rate filings with the Public Utilities Commission:

(C)	To signify changed listing, rule, or condition which may affect rates or charges.
(D)	To signify discontinued material, including listing, rate, rule or condition.
(I)	To signify increase.
(L)	To signify material relocated from or to another part of tariff schedules with no change in text, rate, rule or condition.
(N)	To signify new material including listing, rate, rule or condition.
(R)	To signify reduction.
(T)	To signify change in wording of text but no change in rate, rule or condition.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule - SDPUC Volume No. 2

Section No. 3
5th Revised Sheet No. 1
Canceling 4th Revised Sheet No. 1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	PGA Items	Total Rate/ Dk
Residential Rate 60	2	$0.25 per day	$1.435	$7.340	$8.775
Ellsworth Air Force Base Rate 64	5	$95.00 per month	$0.062	$5.739	$5.801
East River Gas System Rate 66	7				
Meters rated < 500 cubic feet		$2.00 per month			
Meters rated > 500 cubic feet		$4.00 per month	$1.761	$7.469	$9.230
Firm General Service Rate 70	11				
Meters rated < 500 cubic feet		$0.33 per day			
Meters rated > 500 cubic feet		$0.66 per day	$1.078	$7.340	$8.418
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	12	$50.00 per month	$0.453	$7.340	$7.793
Optional Seasonal Gas Service Rate 72	13				
Meters rated < 500 cubic feet		$0.33 per day			
Meters rated > 500 cubic feet		$0.66 per day			
Winter Gas Usage			$1.078	$7.778	$8.856
Summer Gas Usage			$1.078	$6.215	$7.293
Transportation Service	22				
Small Interruptible Rate 81		$125.00 per month			
Maximum			$0.453		
Minimum			$0.131		
Fuel Charge				$0.078	
Large Interruptible Rate 82		$200.00 per month			
Maximum			$0.177		
Minimum			$0.090		
Fuel Charge				$0.064	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	26	$150.00 per month	$0.177	$6.575	$6.752

Date Filed: May 10, 2004

Effective Date: Bills rendered on and after June 1, 2004

Issued By: Donald R. Ball
Asst. Vice President - Regulatory Affairs

Docket No.: NG02-011

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 2
Canceling Vol. 1 19th Rev. Sheet No. 1

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served, except for those communities set forth on Rate 66, for all domestic uses. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	$0.25 per day
Distribution Delivery Charge:	$1.435 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

General Terms and Conditions:

RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 5
Canceling Vol. 1 2nd Rev. Sheet No. 5

ELLSWORTH AIR FORCE BASE Rate 64

Availability:

Service under this rate schedule is available, on an interruptible basis, to the Ellsworth Air Force Base (EAFB).

Rate:

Basic Service Charge:	$95.00 per month
Distribution Delivery Charge:	$0.062 per dk
Cost of Gas:	Determined Monthly - See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Gas Delivery Management Fee:

In addition to the charges set forth above, all volumes of natural gas delivered under this rate schedule shall be subject to a gas Delivery Management Fee. The charge per dk is a negotiable fee subject to approval by the South Dakota Public Utilities Commission.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

ELLSWORTH AIR FORCE BASE Rate 64

General Terms and Conditions:

1. PRIORITY OF SERVICE - Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the Provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $30.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. CONTRACT - Terms of service other than the rate shall be as specified in contracts between EAFB and the Company.

4. RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 7
Canceling Vol. 1 1st Rev. Sheet No. 7

EAST RIVER NATURAL GAS SYSTEM
GENERAL SERVICES Rate 66

Availability:

For all purposes in the following communities, except for resale:

Agar	Glenham	Pierre
Bowdle	Ipswich	Roscoe
Ft. Pierre	Mobridge	Selby
Gettysburg	Onida	

Rate:

Basic Service Charge Per Month:
For customers with meters rated under 500 cubic feet per hour $2.00
For customers with meters rated over 500 cubic feet per hour $4.00

Distribution Delivery Charge:	All dk @$1.761 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 89 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

RULES - The foregoing schedule is subject to Rates 100 through 134, and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: December 30, 2002
Effective Date: Service Rendered on and after December 2, 2003
Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs
Implemented December 4, 2003
Docket No.: NG02-011

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 11
Canceling Vol. 1 2nd Rev. Sheet No. 11

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served, except for those communities set forth on Rate 66, for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.33 per day
For customers with meters rated over 500 cubic feet per hour	$0.66 per day
Distribution Delivery Charge:	$1.078 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 11.1

FIRM GENERAL GAS SERVICE Rate 70

General Terms and Conditions:

RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
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400 N 4th Street
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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 12
Canceling Vol. 1 1st Rev. Sheet No. 12

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Availability:

In all communities served, except for communities set forth on Rate 66, for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 40,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$50.00 per month
Distribution Delivery Charge:	
Maximum Rate	$0.453 per dk
Minimum Rate	$0.131 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

General Terms and Conditions:

1. PRIORITY OF SERVICE - Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the Provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $30.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. AGREEMENT - Upon request of the Company, customer may be required to enter into an agreement for service hereunder. If mutually agreed to by the Company and customer, the term of service reflected in such agreement may be amended. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under another appropriate rate schedule for the customer's operations.

Montana-Dakota Utilities Co.
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400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS - Remote data acquisition equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder.

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the remote data acquisition equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment.

6. RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 13
Canceling Vol. 1 2nd Rev. Sheet No. 13

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served, except for those communities set forth on Rate 66, for customers otherwise qualifying for service under Firm General Gas Service Rate 70. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.33 per day
For customers with meters rated over 500 cubic feet per hour	$0.66 per day
Distribution Delivery Charge:	$1.078 per dk
Cost of Gas:	
Winter – Bills rendered October 1 through March 31	Determined Monthly – See Rate Summary Sheet for Current Rate
Summer – Bills rendered April 1 through September 30	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Montana-Dakota Utilities Co.
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400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

General Terms and Conditions:

1. TERM - The customer agrees to contract for service under the Optional Seasonal General Gas Service Rate 72 for a minimum of one year.

2. RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 22
Canceling Vol. 1 1st Rev. Sheet No. 22

TRANSPORTATION SERVICE Rates 81 and 82

Availability:

This service is applicable, except for customers served on Rate 66, for transportation of natural gas to customer's premise (metered at a single delivery point) through Company's distribution facilities. In order to obtain transportation service, customer must qualify under an applicable gas transportation service rate; meet the general terms and conditions of service provided hereunder; and enter into a gas transportation agreement upon request by the Company.

The transportation services are as follows:

Small Interruptible General Gas Transportation Service Rate 81:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point whose average use of natural gas will not exceed 40,000 dk annually, and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to Company's effective Small Interruptible General Gas Service Rate 71. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70.

Large Interruptible General Gas Transportation Service Rate 82:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point, whose average use of natural gas will exceed 40,000 dk annually, and who, absent the request for transportation service, are eligible for natural gas service on an interruptible basis, pursuant to Company's effective Large Interruptible General Gas Service Rate 85. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70.

Montana-Dakota Utilities Co.
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Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TRANSPORTATION SERVICE Rates 81 and 82

Rate:

Basic Service Charge:

Rate 81	$125.00 per month 1/
Rate 82	$200.00 per month 2/

1/ In the event customer takes service through one meter under both Rates 71 and 81, the base rate under Rate 81 shall be waived.

2/ In the event customer takes service through one meter under both Rates 85 and 82, the base rate under Rate 82 shall be waived.

Under Rates 81 or 82 customer shall pay a negotiated rate not more than the maximum rate or less than the minimum rate specified below. (The per dk charge is applicable to all dk of natural gas transported under the terms of this rate.)

	Rate 81	Rate 82
Maximum Rate per dk	$0.453	$0.177
Minimum Rate per dk	$0.131	$0.090
Balancing Charge per dk	$0.300	$0.300

Fuel Charge:

Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See Rate Summary Sheet for currently effective charge.

GENERAL TERMS AND CONDITIONS:

1. CRITERIA FOR SERVICE – In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. The customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

2. REQUEST FOR GAS TRANSPORTATION SERVICE: To qualify for gas transportation service a customer must request the service pursuant to the provisions set forth herein. The service shall be provided only to the extent that the Company's existing operating capacity permits.

3. MULTIPLE SERVICES THROUGH ONE METER:
   a. In the event customer desires firm sales service in addition to gas transportation service, customer shall request such firm volume requirements, and upon approval by Company, such firm volume requirements shall be set forth in a firm service agreement. For billing purposes, the level of volumes so specified or the actual volume used, whichever is lower, shall be billed at Rate 70. Volumes delivered in excess of such firm volumes shall be billed at the applicable gas transportation rate. Customer has the option to install, at their expense, piping necessary for separate measurement of sales and transportation volumes.

   b. The customer shall pay, in addition to charges specified in the applicable gas transportation rate schedule, charges under all other applicable rate schedules for any service in addition to that provided herein (irrespective of whether the customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE - Company shall have the right to curtail or interrupt deliveries without being required to give previous notice of intention to curtail or interrupt, whenever, in its judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

5. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken above that received on the customer's behalf, shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail

or interrupt, or $30.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

6. NON-DELIVERED VOLUMES/PENALTY:
   a. In the event customer uses more gas than is being delivered to the Company's interconnection with the delivering pipeline(s) (receipt point), customer shall pay an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the same receipt point, any payment or overrun penalties the Company is required to make shall be allocated on a pro rata basis among such customers on the basis of each customer's use of gas in excess of available volumes.

   b. In the event the customer's gas is not being delivered to the receipt point for any reason and the customer continues to take gas, the customer shall be subject to any applicable penalties or charges set forth in Paragraph 6.a. Gas volumes supplied by Company will be billed at Firm General Service Rate 70 (distribution delivery charge and cost of gas). The Company is under no obligation to notify customer of non-delivered volumes.

   c. In the event customer's transportation volumes are not available for any reason, customer may take interruptible sales service if such service is available. The availability of interruptible sales service shall be determined at the sole discretion of the Company.

7. ELECTION OF SERVICE - Prior to the initiation of service hereunder, the customer shall make an election of its requirements under each applicable rate schedule for the entire term of service. If mutually agreed to by the Company and customer, the term of service may be amended. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the

Company, gas service under the appropriate sales rate schedule for the customer's operations.

8. RECONNECTION FEE - Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge as specified in Rate 100, §V.18.

9. BALANCING:
   a. To the extent practicable, customer and Company agree to the daily balancing of volumes of gas received and delivered on a thermal basis. Such balancing is subject to the customer's request and the Company's discretion to vary scheduled receipts and deliveries within existing Company operating limitations. If, at the end of a billing month, the accumulated difference between actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer exceeds 4% of that month's scheduled receipts, resulting in a negative imbalance (i.e., deliveries exceed scheduled receipts), the customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, the customer shall then be billed, in addition to the applicable transportation rate, a penalty for the under nominated volume exceeding 4% at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas). The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume on which a penalty was imposed. If, at the end of a billing month, the accumulated difference between nominated (scheduled) receipts on behalf of such customer and actual gas deliveries to the customer exceeds 4% of that month's scheduled receipts, resulting in a positive imbalance (i.e., scheduled receipts exceed deliveries), the customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, (1) the Company may adjust the volume of gas received on behalf of the customer so as to eliminate the prior period over nomination exceeding 4% up to 10% and (2) the Company shall retain the over nomination of gas exceeding 10% free and clear of any adverse claims relating thereto when such accumulated difference

exceeds 50 dk. The accumulated difference between the actual gas deliveries to the customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume retained.

b. In the event customer's imbalance causes the Company to incur a balancing penalty from its interconnecting pipeline(s), customer shall pay any penalty payments or overrun charges the Company is required to make under the terms of its contract(s) with interconnecting pipeline(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the same interconnection with a delivering pipeline, any payment or overrun penalties the Company is required to make shall be apportioned among such customers on the basis of each customer's contribution toward the imbalance.

c. Customer's nominations made to clear imbalances will be subject to the priority of service and allocation of capacity provisions set forth in Rate 100, §V.10, and the penalties for failure to curtail or interrupt use of gas set forth in Paragraph 5 of this rate schedule.

d. Termination of the gas transportation service shall not relieve Company and customer of the obligation to correct any quantity imbalances hereunder or customer of the obligation to pay money due hereunder to Company.

e. The Company may waive any penalty associated with Company adjustments to end-use customer nominations in those instances where the Company, due to operating limitations, is required to adjust end-use transportation customer nominations and such Company adjustments create a penalty situation, or preclude a customer from correcting an imbalance which results in a penalty.

10. NOMINATION VARIANCE CHARGE - The customer shall pay, any payments the Company must make to its interconnecting pipeline(s), as a result of nomination variance penalties caused by customer's nomination variances. Such penalties will be allocated on the basis of each customer's contribution toward the nomination variance.

11. METERING REQUIREMENTS Remote data acquisition equipment required by the Company for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder. The cost of the equipment and its installation shall be paid for by the customer. Such contribution in aid, as adjusted for federal income taxes, shall be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. Company may remove such equipment when service hereunder is terminated. The customer shall provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and acceptable telephone service at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure Company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the remote data acquisition equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

12. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper and/or agent shall advise Company's gas nominations center, by 11:30 a.m. Central Clock Time, of the dk requirements customer has requested to be delivered at each delivery point during the following day. Customer's daily nomination shall be its best estimate of the expected utilization for the gas day. Unless other arrangements are made, customer will be required to nominate for the non-business days involved prior to weekends and holidays.

    b. All nominations should include shipper and/or agent defined begin and end dates. Shippers and/or agents may nominate for periods longer than 1 day, provided the nomination begin and end dates are within the term of the service agreement.

    c. The Company has the sole right to refuse receipt of any volumes which exceed the maximum daily contract quantity and at no time shall the Company be required to accept quantities of gas for a customer in

excess of the quantities of gas to be delivered to customer. If total nominated receipts exceed total deliveries at receipt points where more than one customer is receiving service, nominations will be allocated on a pro rata basis. At no time shall Company have the responsibility to deliver gas in excess of customer's nomination.

d. In the event that more than one customer is receiving gas from the same shipper and/or agent at the same receipt point, any reduction in nominated volumes will be allocated on a pro rata basis, unless Company and shipper(s) and/or agent(s) have agreed to a predetermined allocation procedure.

13. WARRANTY - The customer, customer's agent, or customer's shipper warrants that it will have title to all gas it tenders or causes to be tendered to the Company, and such gas shall be free and clear of all liens and adverse claims and the customer, customer's agent, or customer's shipper shall indemnify the Company against all damages, costs, and expenses of any nature whatsoever arising from every claim against said gas.

14. FACILITY EXTENSIONS - If facilities are required in order to furnish gas transportation service, and those facilities are in addition to the facilities required to furnish firm gas service, the customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. Company may remove such facilities when service hereunder is terminated.

15. PAYMENT - Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendment or alterations thereto.

16. BILLING ERROR - In the event an error is discovered in any bill that the Company renders to customer, such error shall be adjusted within a period not to exceed 6 months from the date the billing error is first discovered.

17. AGREEMENT - Upon request of the Company, customer may be required to enter into an agreement for service hereunder.

Montana-Dakota Utilities Co.
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400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TRANSPORTATION SERVICE Rates 81 and 82

18. RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
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Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 26
Canceling Vol. 1 1st Rev. Sheet No. 26

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served, except those communities set forth on Rate 66, for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will exceed 40,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement. The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

This rate schedule shall not apply for service to U. S. Government installations, which are covered by separate special contracts.

Rate:

Basic Service Charge:	$150.00 per month
Distribution Delivery Charge:	
Maximum Rate	$0.177 per dk
Minimum Rate	$0.090 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Montana-Dakota Utilities Co.
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400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

General Terms and Conditions:

1. PRIORITY OF SERVICE - Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company's firm general gas service rates. Customers taking service hereunder agree that the Company without prior notice shall have the right to curtail or interrupt such service whenever, in Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company any gas taken shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payment(s) or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $30.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

3. AGREEMENT - Upon request of the Company, customer may be required to enter into an agreement for service hereunder. If mutually agreed to by the Company and customer, the term of service reflected in such agreement may be amended. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under another appropriate rate schedule for the customer's operations.

Montana-Dakota Utilities Co.
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400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS – Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS – Remote data acquisition equipment required for daily measurement will be installed by the Company, at its sole discretion, prior to the initiation of service hereunder.

   The customer shall be required to provide and maintain, at no cost to Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company, and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure company of a quality telephone signal necessary to properly transmit data. The customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the remote data acquisition equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment.

6. RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 28

DISTRIBUTION DELIVERY STABILIZATION MECHANISM – Rate 87

APPLICABILITY:

This rate schedule represents a Distribution Delivery Stabilization Mechanism (DDSM) and specifies the procedure to be utilized to correct for the over/under collection of distribution delivery charge revenues due to weather fluctuations during the period from October 1 through April 30. Service provided under the Company's Residential Rate 60 and Firm General Service Rate 70 shall be subject to decreases or increases under the DDSM.

DISTRIBUTION DELIVERY STABILIZATION MECHANISM:

A DDSM will be determined for each customer taking service under Residential Service Rate 60 and Firm General Service Rate 70 beginning with the first billing cycle starting November 1 through the billing cycle ending May 1. The DDSM adjustment will be applied as a surcharge or credit on all rate schedules to which the DDSM is applicable.

DDSM ADJUSTMENT CALCULATION:

The DDSM Adjustment shall be determined for each customer taking service under Residential Rate 60 or Firm General Service Rate 70. In order to calculate the respective DDSM adjustment, the ratio of the normal HDDs as compared to the actual HDDs will be determined and multiplied by the temperature sensitive consumption per customer per HDD, as determined in the most recent general rate case. The resulting product shall be multiplied by the applicable Distribution Delivery Charge rate per dk.

$$DDSM_i = R_i\,(DDF_i\,((NDD\text{-}ADD)/NDD))$$

Where:

$DDSM_i$	=	Distribution Delivery Stabilization Adjustment
i	=	Customer served under Rate Schedule 60 or 70
R_i	=	Applicable Distribution Delivery Charge per dk
DDF_i	=	Temperature sensitive use per customer
NDD	=	Normal degree days for the applicable bill cycle
ADD	=	Actual heating degree days for the applicable bill cycle

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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

DISTRIBUTION DELIVERY STABILIZATION MECHANISM – Rate 87

DEFINITIONS:

Heating Degree Days	-	The average of the daily high and low temperatures as reported by the National Weather Service station located at the Rapid City Regional Airport subtracted from 65 degrees Fahrenheit.
Normal Degree Days	-	The heating degree days based on the 30-year average for the period 1970-2000.
Temperature Sensitive Use per Customer	-	Customer's actual use less the base use per customer per day, denoted below, multiplied by days in the billing period. Residential (Rate Code 600 and 601)=0.0630 Dk/Degree Day Firm General (Rate Code 700) = 0.0929 Dk/Degree Day Firm General (Rate Code 701) = 1.2728 Dk/Degree Day
Actual Degree Days	-	The actual degree days reported by the National Weather Service Station located at the Rapid City Regional Airport.

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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 29
Canceling Vol. 1 3rd Rev. Sheet No. 29

PURCHASED GAS COST ADJUSTMENT Rate 88

1. Applicability:

This rate schedule constitutes a purchased gas cost adjustment (PGA) provision and specifies the procedure to be utilized to adjust the rates for gas sold under Montana-Dakota's rate schedules, with the exception of General Service Rate 66, in order to reflect: (a) changes in Montana-Dakota's average cost of gas supply and (b) amortization of the Unrecovered Purchased Gas Cost Account.

2. Effective Date and Limitation on Adjustments:

(a) The effective dates of the PGA shall be bills rendered on and after the first day of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file a PGA to reflect changes in its average cost of gas supply only when the amount of change in such PGA is at least 10 (ten) cents per dk compared to the currently effective adjustment. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. Purchased Gas Cost Adjustment:

(a) The monthly PGA shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent PGA. The cost of gas supply shall be the sum of all costs incurred in obtaining gas for general system supply. General system supply is defined as gas available for use by all customers served under retail sales rate schedules excluding Rate 66. The cost of gas supply shall include, but not be limited to, all demand, commodity, storage, gathering, and transportation charges incurred by Montana-Dakota for such gas supply, the overall rate of return on prepaid demand and commodity charges and gas storage balances required to maintain the system gas supply and hedging program gains, losses and transaction costs related to system gas supply.

(b) The PGA shall be computed as follows:

(1) Demand costs shall include all annual gathering, transportation and storage demand charges at current rates.

(2) Commodity costs shall include all annual gathering, transportation and storage charges at current rates.

(3) The gas commodity cost shall reflect all commodity related gas costs estimated to be in effect for the month the PGA will be in effect and annual dk requirements.

(4) The return on prepaid demand and commodity balances and storage balances shall be computed on an annual basis at the overall rate of return on rate base.

The cost per dk for the month is the sum of the above divided by annual, weather normalized dk deliveries for the most recent twelve month period adjusted to reflect losses.

(c) Monthly gas costs shall be calculated as follows:

(1) Demand costs shall be apportioned to all state jurisdictions served by Montana-Dakota on the basis of the overall ratio of each state's Maximum Daily Delivery Quantity (MDDQ).

(2) Demand costs for large interruptible sales customers shall be stated on a 100% load factor basis.

(3) All commodity costs and other costs associated with the acquisition of gas for general system supply shall be apportioned to each state on the basis of total dks sold in each state, regardless of the actual points of delivery of such gas.

(4) The return requirement related to prepaid demand and commodity charges and gas storage balances shall be included on a per dk basis. The prepaid demand and storage balances shall be apportioned to all states on the basis of each state's MDDQ. The prepaid commodity charges shall be apportioned to all states on the basis of annual dks sold in each state. The unit cost shall be calculated using a thirteen month average balance and the currently authorized return on rate base.

(5) All costs related to specific end-use transactions shall not be included in the cost of gas supply determination but shall be directly billed to the customer(s) contracting for such service.

(d) The PGA shall be applied to each of Montana-Dakota's rate schedules excluding Rate 66, recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

4. Surcharge Adjustment:

All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on May 1 of each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Gas Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

5. Unrecovered Purchase Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Cost Account, as calculated in accordance with Subsection 5(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in a Purchased Gas Cost Adjustment by reason of the ten cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for gas supplies which were paid during any period after the effective date of the most recent general rate case, but not yet included in sales rates.

(3) Refunds received from supplier(s) with respect to gas supply. Such refunds received shall be credited to the Unrecovered Purchased Gas Cost Account.

(4) Carrying charges or credits as determined in Section 5(b)(2).

(5) Demand costs recovered from the large interruptible sales customers will be credited to the residential, firm general service and small interruptible customers.

(b) (1) The amount to be included in the Unrecovered Purchased Gas Cost Account in order to reflect the items specified in Subsections 5(a)(1), (2), and (3) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's natural gas supply as adjusted to levelize demand charges.

Such adjustment to levelize supplier(s) demand charges shall be calculated as follows:

The suppliers' annual (calendar or fiscal) demand charges, which are payable in equal monthly payments, shall be accumulated in a prepaid account (FERC Account 165). Each month a portion of such accumulated prepaid amount shall be amortized to cost of natural gas purchased (FERC Account 804). Such monthly amortization shall be based on a rate calculated by dividing the annual supplier(s) demand charges by projected annual natural gas sales units (calendar or fiscal, as appropriate). The resulting product shall then be multiplied by the projected natural gas unit sales for the current month. Such amount shall constitute the monthly amortization of prepaid supplier(s) demand charges to cost of natural gas supply.

(ii) Montana-Dakota shall then subtract from each month's unit cost the unit cost for gas supply which is reflected in the currently effective PGA.

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each rate schedule. The resulting amounts shall be reflected in an Unrecovered Purchased Gas Cost Account for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Gas Cost Account, Account 191, at the rate of interest for a three-month Treasury Bill as published monthly by the Federal Reserve Board for the preceding month. The amount to be included in Account 191 for carrying charges shall be determined as follows: each month, Account 191 shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

(i) The balance in Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the annual interest rate as set forth in this Subsection (b)(2). The carrying charges shall be accrued in a supplementary Unrecovered Purchased Gas Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in the Unrecovered Purchased Gas Cost Account:

(1) The amounts in the Unrecovered Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule excluding Rate 66. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Gas Cost Account specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Unrecovered Purchased Gas Cost Account specified in Subsection 5(a)(4).

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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

PURCHASED GAS COST ADJUSTMENT Rate 88

6. Time and Manner of Filing:

(a) Each filing by Montana-Dakota shall be made by means of revised PGA sheets identifying the amounts of the adjustments and the resulting currently effective PGA rates.

(b) Each filing shall be accompanied by detailed computations which clearly show the derivation of the relevant amounts.

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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 30
Canceling Vol. 1 4th Rev. Sheet No. 30

EAST RIVER NATURAL GAS SYSTEM
PURCHASED GAS COST ADJUSTMENT Rate 89

1. Applicability:

This rate schedule constitutes a purchased gas cost adjustment (PGA) provision and specifies the procedure to be utilized to adjust the rates for gas sold under General Services Rate 66 in order to reflect: (a) changes in Montana-Dakota's average cost of gas supply and (b) amortization of the Unrecovered Purchased Gas Cost Account.

2. Effective Date and Limitation on Adjustments:

(a) The effective dates of the PGA shall be bills rendered on and after the first day of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file a PGA to reflect changes in its average cost of gas supply only when the amount of such change in PGA is at least 10 (ten) cents per dk compared to the currently effective adjustment. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. Purchased Gas Cost Adjustment:

(a) The monthly PGA shall reflect changes in Montana-Dakota's cost of gas supply for the East River System as compared to the cost of gas supply approved in its most recent PGA. The cost of gas supply shall be the sum of all costs incurred in obtaining gas for delivery at interconnections with South Dakota Intrastate Pipeline (SDIP). The East River System supply is defined as gas available for use by all customers served under General Services Rate 66. The cost of gas supply shall include, but not be limited to, all demand, commodity, storage, gathering, and transportation charges incurred by Montana-Dakota for such gas supply, the overall rate of return on prepaid demand and commodity charges and gas storage balances required to maintain the East River System gas supply and hedging program gains, losses and transaction costs related to the East River System gas supply.

(b) The PGA shall be computed as follows:

(1) Demand Costs, if applicable, shall include all annual gathering, transportation and storage demand charges at current rates.

(2) Commodity costs shall include all annual gathering, transportation and storage charges at current rates.

(3) The gas commodity cost shall reflect all commodity related gas costs estimated to be in effect for the month the PGA will be in effect and annual dk requirements.

(4) The return on prepaid demand and commodity balances and storage balances, if applicable, shall be computed on an annual basis at the overall rate of return on rate base.

The cost per dk for the month is the sum of the above divided by annual, weather normalized dk deliveries for the most recent twelve-month period adjusted to reflect losses.

(c) Monthly gas costs shall be calculated as follows:

(1) Demand costs if applicable, shall be apportioned to all state jurisdictions served by Montana-Dakota on the basis of the overall ration of each state's Maximum Daily Delivery Quantity (MDDQ).

(2) Demand costs for interruptible and specified contract service customers shall be stated on a 100% load factor basis.

(3) All commodity costs and other costs associated with the acquisition of gas for the East River System Supply.

(4) The return requirement related to prepaid demand and commodity charges and gas storage balances, if applicable, shall be included on a per dk basis. The prepaid demand and storage balances shall be apportioned to all states on the basis of each state's MDDQ. The prepaid commodity charges shall be apportioned to all states on the basis of annual dk's sold in each state. The unit cost shall be calculated using a thirteen month average balance and the currently authorized return on rate base.

(5) All costs related to specific end-use transactions shall not be included in the cost of gas supply determination but shall be directly billed to the customer(s) contracting for such service.

(d) The PGA shall be applied to General Services Rate 66, if applicable, recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

4. Surcharge Adjustment:

General Services Rate 66 shall be subject to a Surcharge Adjustment to be effective on May 1 of each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Gas Cost Account calculated by dividing the applicable balance by the estimated General Services Rate 66 dk sales for the twelve months following the effective date of the adjustment.

5. Unrecovered Purchased Gas Cost Account:

(a) Items to be included in the Unrecovered Purchased Gas Cost Account, as calculated in accordance with Subsection 5(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in a Purchased Gas Cost Adjustment by reason of the ten cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for gas supplies which were paid during any period after the effective date of the most recent general rate case, but not yet included in the East River System sales rates.

(3) Refunds received from supplier(s) with respect to gas supply. Such refunds received shall be credited to the Unrecovered Purchased Gas Cost Account.

(4) Carrying charges or credits as determined in Section 5(b)(2).

(b) (1) The amount to be included in the Unrecovered Purchased Gas Cost Account in order to reflect the items specified in Subsections 5(a)(1), (2), and (3) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's natural gas supply as adjusted to levelize demand charges, if applicable. Such adjustment to levelize supplier(s) demand charges shall be calculated as follows:

The suppliers' annual (calendar or fiscal) demand charges, which are payable in equal monthly payments, shall be accumulated in a prepaid account (FERC Account 165). Each month a portion of such accumulated prepaid amount shall be amortized to cost of natural gas purchased (FERC Account 804).

Such monthly amortization shall be based on a rate calculated by dividing the annual supplier(s) demand charges by projected annual natural gas sales units (calendar or fiscal, as appropriate). The resulting product shall then be multiplied by the projected natural gas unit sales for the current month. Such amount shall constitute the monthly amortization of prepaid supplier(s) demand charges to cost of natural gas supply.

(ii) Montana-Dakota shall then subtract from each month's unit cost the unit cost for gas supply which is reflected in the currently effective PGA.

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under General Services Rate 66. The resulting amounts shall be reflected in an Unrecovered Purchased Gas Cost Account for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in the Unrecovered Purchased Gas Cost Account, Account 191, at the rate of interest for a three-month Treasury Bill as published monthly by the Federal Reserve Board for the preceding month. The amount to be included in Account 191 for carrying charges shall be determined as follows: each month, Account 191 shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

(i) The balance in Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the annual interest rate as set forth in this Subsection (b)(2). The carrying charges shall be accrued in a supplementary Unrecovered Purchased Gas Cost Account for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in the Unrecovered Purchased Gas Cost Account:

(1) The amounts in the Unrecovered Purchased Gas Cost Account shall be decreased each month by an amount determined by

multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under General Services Rate 66. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in the Unrecovered Purchased Gas Cost Account specified in Subsections 5(a)(1), (2), (3) and the amounts in the supplementary Unrecovered Purchased Gas Cost Account specified in Subsection 5(a)(4).

6. Time and Manner of Filing:

(a) Each filing by Montana-Dakota shall be made by means of revised PGA sheets identifying the amounts of the adjustments and the resulting currently effective PGA rates.

(b) Each filing shall be accompanied by detailed computations which clearly show the derivation of the relevant amounts.

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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 4
1st Revised Sheet No. 1
Canceling Original Sheet No. 1

LIST OF GAS CONTRACTS WITH DEVIATIONS

Name and Location of Customer	Type or Class of Service	Execution and Expiration Dates	Most Comparable Regular Tariff: Schedule No.	Most Comparable Regular Tariff: Contract Differences
Morris, Inc.	Firm Commercial	05-10-01 To 11-16-11	Rate 66	Rate
Merillat Corporation	Firm Commercial	11-01-03 To 10-31-04	Rate 70	Rate

Date Filed: December 26, 2003
Effective Date: Service Rendered on and after October 28, 2003
Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs
Docket No.: NG03-005

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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 1
Canceling Vol. 1 1st Rev. Sheet No. 1

TABLE OF CONTENTS
GENERAL PROVISIONS Rate 100

Title		Page No.
I.	Purpose	3
II.	Definitions	3-4
III.	Customer Obligations	
	1. Application for Service	5
	2. Input Rating	5
	3. Access to Customer's Premises	6
	4. Company Property	6
	5. Interference with Company Property	6
	6. Relocated Lines	6
	7. Notification of Leaks	6
	8. Termination of Gas Service	6
	9. Reporting Requirement	6
IV.	Liability	
	1. Continuity of Service	7
	2. Customer's Equipment	7
	3. Company Equipment and Use of Service	7
	4. Indemnification	7
	5. Force Majeure	7-8
V.	General Terms and Conditions	
	1. Agreement	9
	2. Rate Options	9
	3. Rules for Application of Gas Service	9-10
	4. Dispatching	10
	5. Rules Covering Gas Service to Manufactured Homes	10
	6. Consumer Deposits	10-11
	7. Metering and Measurement	12
	8. Measurement Unit for Billing Purposes	12
	9. Unit of Volume for Measurement	13
	10.Priority of Service & Allocation of Capacity	13-14

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 1.1
Canceling Vol. 1 1st Rev. Sheet No. 1.1

TABLE OF CONTENTS
GENERAL PROVISIONS Rate 100

11. Late Payment	14
12. Returned Check Charge	14
13. Tax Clause	14
14. Utility Customer Services	15
15. Utility Services Performed after Normal Business Hours	15
16. Notice to Discontinue Gas Service	16
17. Installing Temporary Metering Facilities or Service	16
18. Reconnection Fee for Seasonal or Temporary Customers	16
19. Disconnection of Service for Nonpayment of Bills	16
20. Disconnection of Service for Causes other than Nonpayment of Bills	17
21. Unauthorized Use of Service	18-19
22. Gas Meter Test by Customer Request	19-20
23. Additional Rates Identifying Special Provisions	20

I. PURPOSE:

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other accepted standards and practices not covered herein. They are intended to ensure adequate service to the public and protect the Company from unreasonable demands.

The Company undertakes to furnish service subject to the rules and regulations of the Public Utilities Commission of South Dakota and as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. DEFINITIONS:

The following terms used in this tariff shall have the following meanings, unless otherwise indicated:

AGENT – The party authorized by the transportation service customer to act on that customer's behalf.

APPLICANT – A customer requesting Company to provide service.

COMMISSION – Public Utilities Commission of the State of South Dakota.

COMPANY – Montana-Dakota Utilities Co.

COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the customer's convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.

CURTAILMENT – A reduction of transportation or retail natural gas service deemed necessary by the Company. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.

CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by Company at one location and at one point of delivery unless otherwise expressly provided in these rules or in a rate schedule.

DELIVERY POINT – The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of Company's meter(s) located on customer's premises.

GAS DAY – Means a period of twenty-four consecutive hours, beginning and ending at 9:00 A.M. Central Clock Time.

HOUSEHOLD – A family or a group of people who live together.

INDEBTED HOUSEHOLD – A group of people living together among whom there is one who is indebted to a gas utility for service provided previously to the residence for which service is now sought.

INTERRUPTION – A cessation of transportation or retail natural gas service deemed necessary by Company.

NOMINATION – The daily dk volume of natural gas requested by customer for transportation and delivery to customer at the delivery point during a gas day.

PIPELINE – The transmission company(s) delivering natural gas into company's system.

RATE – Shall mean and include every compensation, charge, fare, toll, rental and classification, or any of them, demanded, observed, charged or collected by the Company for any service, product, or commodity, offered by the Company to the public, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

RECEIPT POINT – The intertie between Company and the interconnecting pipeline(s) at which point Company assumes custody of the gas being transported.

SHIPPER – The party with whom the Pipeline has entered into a service agreement for transportation services.

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE – A customer desiring gas service must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. The Company may refuse a customer or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any customer who uses gas service in the absence of application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

   Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

   Any customer may be asked to make a deposit as required.

2. INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at Company's sole discretion, Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will insure that such equipment will conform to the Company's ability to adequately serve such installations with gas.

3. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

4. COMPANY PROPERTY – The customers shall exercise reasonable diligence in protecting the Company's property on their premises, and shall be liable to the Company in case of loss or damage caused by their negligence or that of their employees.

5. INTERFERENCE WITH COMPANY PROPERTY – The customer shall not disconnect, change connections, make connections or otherwise interfere with Company's meters or other property or permit same to be done by other than the Company's authorized employees or representatives.

6. RELOCATED LINES – Where Company facilities are located on a public or private utility easement and customer erects or installs a building, over gas facilities (Company-owned main, Company-owned service line or customer-owned service line) the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

7. NOTIFICATION OF LEAKS – The customer shall immediately notify the Company at its office of any escape of gas in or about the customer's premises.

8. TERMINATION OF GAS SERVICE – All customers are required to notify the Company, to prevent their liability for service used by succeeding tenants, when vacating their premises. Upon receipt of such notice, the Company will read the meter and further liability for service used on the part of the vacating customer will cease.

9. REPORTING REQUIREMENTS – Customer shall furnish Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

IV. LIABILITY:

1. CONTINUITY OF SERVICE – The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.

2. CUSTOMER'S EQUIPMENT – Neither by inspection or non-rejection, nor in any other way does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer or leased by the customer from third parties.

3. COMPANY EQUIPMENT AND USE OF SERVICE – The Company will not be liable for any loss, injury, death or damage resulting in any way from the supply or use of gas or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold Company harmless from any and all injury, death, loss or damage resulting from customer's negligent or wrongful acts under and during the term of service. Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from Company's negligent or wrongful acts under and during the term of service.

5. FORCE MAJEURE – In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such

causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of customer's gas are destroyed while in Company's possession by an event of force majeure, the obligations of the parties shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or Company, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

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State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS:

1. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for any service.

2. RATE OPTIONS – Where more than one rate schedule is available for the same class of service, the Company will assist the customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in twelve months unless there is a material change in the customer's load which alters the availability and/or applicability of such rate(s), or unless a change becomes necessary as a result of an order issued by the Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

3. RULES FOR APPLICATION OF GAS SERVICE:
   a. Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, or for the producing operations of a farm or ranch, may be served on the residential rate.

   b. Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty parlors, master metered apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site (this is not an all-inclusive list).

c. The definitions above are based upon the supply of service to an entire premise through a single delivery and metering point. Separate supply for the same customer at other points of consumption may be separately metered and billed.

d. If separate metering is not practical for a single unit (one premise) that is using gas for both domestic purposes and for conducting business (or for nonresidential purposes as defined herein), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the customer's total connected load.

e. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the Nonresidential rates.

4. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by Company to facilitate transportation service. Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES – The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Home Construction and Safety Standards) Subpart G and H which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities. This information is available at Montana-Dakota Utilities Co.'s offices.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with commission rules.

a. The amount of such deposit shall not exceed one-sixth of the estimated annual bill. If a customer has no deposit or one which is inadequate in comparison with his recent bills for service the Company may collect an additional amount in order to bring the total deposit up to the foregoing standard. Should a customer be unable to pay the full amount of the deposit, the Company shall accept payment of the deposit in reasonable installments not to exceed four months.

b. The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall automatically terminate after the customer has established credit that would result in return of a deposit or at the guarantor's request upon sixty days written notice to the Company. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance which the customer owes the Company. Upon termination of a guarantee contract a new contract or a cash deposit may be required by the Company.

c. The customer may in lieu of a deposit be placed on an early payment list whereby customer shall pay the service bill within a minimum of five working days. However for early payment, early disconnection shall be proper when a customer fails to pay the service bill within a minimum of five working days.

   A deposit shall earn interest at the rate of 7% per year for such period as the customer receives service. Interest shall be credited to the customer's account annually during the month of December.

   Deposits with interest shall be refunded to customers at termination provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for twelve months, provided satisfactory credit has been established.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

7. METERING AND MEASUREMENT:
   a. Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. Company will test meters in accordance with applicable state utility rules and regulations.

   b. Transportation customers agree to provide the cost of the installation of remote data acquisition equipment to Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the application of a thermal factor to the volumes metered. This thermal factor consists of:

   a. An altitude adjustment factor used to convert metered volumes at local sales base pressure to a standard pressure base of 14.73 psia, and

   b. A Btu adjustment factor used to reflect the heating value of the gas delivered.

9. UNIT OF VOLUME FOR MEASUREMENT – The unit of volume for purpose of measurement shall be one (1) cubic foot of gas at either local sales base pressure or 14.73 psia, as appropriate, and at a temperature base of sixty degrees Fahrenheit (60° F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AGA-3/NX-19, as amended, supercompressiblity calculation. Supercompressibility factor adjustments will be waived on monthly billed volumes of 250 dk or less.

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from Highest to Lowest:
    a. Priority 1 – Firm sales service.
    b. Priority 2 – Small interruptible sales and small interruptible transportation services at the maximum rate on a pro rata basis.
    c. Priority 3 – Large interruptible sales and large interruptible transportation services at the maximum rate on a pro rata basis.
    d. Priority 4 – Small interruptible sales and small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    e. Priority 5 – Large interruptible sales and large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    f. Priority 6 – Gas scheduled to clear imbalances.

Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

Montana-Dakota reserves the right to provide service to customers with a lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

11. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

12. RETURNED CHECK CHARGE – A charge of $20.00 will be collected by the Company for each check charged back to the Company by a bank.

13. TAX CLAUSE – In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any sales, use or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

    The charges to be added to the customers' service bills under this clause shall be limited to the customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.

14. UTILITY CUSTOMER SERVICES:
    a. The following services will be performed at no charge regardless of the time of performance:

        1. Fire and explosions calls.

        2. Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustible fumes.

        3. Maintenance or repair of Company-owned facilities on the customer's premises.

    b. The following service calls will be performed at no charge during the Company's normal business hours:

        1. Cut-ins and cut-outs.

        2. Lighting pilots, inspecting, and adjusting gas equipment in connection with establishing service when working cut-in orders.

        3. High bills or inadequate service complaints.

        4. Location of underground Company facilities and customer-owned gas service lines for contractors, builders, plumbers, etc.

        5. Service calls for routine cut-ins, when the order is received prior to 12:00 P.M. on a regular work day will be considered as non-chargeable regardless if work is performed outside of normal working hours.

15. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours, a charge will be made for labor at standard overtime service rates and material at retail prices.

    Customers requesting service after the Company's normal business hours will be informed of the after hour service rate and encouraged to have the service performed during normal business hours.

16. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service discontinued shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, personal visit or telephone call to the Company's local business office, in communities in which an office is maintained. In other communities such notice shall be given to the Company's representative who services the community or to the nearest business office. Saturdays, Sundays and legal holidays are not considered business days.

17. INSTALLING TEMPORARY METERING FACILITIES OR SERVICE – A customer requesting a temporary meter installation and service will be charged on the basis of direct costs incurred by the Company.

18. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS – A customer who requests reconnection of service, at a location where same customer discontinued the same service during the preceding 12-month period will be charged the Basic Service Charge applicable during the period service was not being used or a minimum of $30.00 during normal business hours. The minimum will be based on standard overtime rates for reconnecting service after normal business hours.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge of $160.00 whenever reinstallation of the remote data acquisition equipment is necessary.

19. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee of $25.00 before restoring gas service which has been disconnected for nonpayment of service bills during normal business hours. Standard overtime rates will apply for services performed after normal business hours.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

20. DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS – The Company reserves the right to discontinue service for any of the following reasons:

    a. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

    b. In the event of tampering with the equipment furnished and owned by the Company.

    c. For violation of or noncompliance with the Company's rules on file with the Commission.

    d. For failure of the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

    e. For refusal of reasonable access to property to the agent or employee of the Company for the purpose of inspecting the facilities or for testing, reading, maintaining or removing meters.

The right to discontinue service for any of the above reasons may be exercised whenever and as often as such reasons may occur, and any delay on the part of the Company in exercising such rights, or omission of any action permissible hereunder, shall not be deemed a waiver of its rights to exercise same.

Nothing in these regulations shall be construed to prevent discontinuing service without advance notice for reasons of safety, health, cooperation with civil authorities, or fraudulent use, tampering with or destroying Company facilities.

The Company may collect a reconnect fee of $30.00 before restoring gas service which has been disconnected for the above causes.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

20. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference or tampering with a Company meter, pressure regulator, registration, connections, equipment, seals, valve, procedures or records resulting in a loss of revenue to the Company. Unauthorized service includes reconnection of service, that has been terminated, without the Company's consent.

    a. Types of unauthorized use of service includes, but is not limited to, tampering or unauthorized reconnection by the following methods:

        1. Bypass piping around meter.
        2. Bypass piping installed in place of meter.
        3. Meter reversed.
        4. Meter index disengaged or removed.
        5. Service or equipment tampered with or piping connected ahead of meter.
        6. Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
        7. Gas being used after service has been discontinued by the Company.
        8. Gas being used after service has been discontinued by the Company as a result of a new customer turning gas on without the proper connect request.

    b. Any charges for damage to Company property will be billed to the customer. The customer may also be charged for:

        1. Time, material and transportation costs used in investigation or surveillance.
        2. Estimated charge for non-metered gas.
        3. On-premise time to correct situation.
        4. A minimum fee of $30.00 will apply.

        All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company.

c. Reconnection of Service:
Customer service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid any service charges which are due, including:

1. All delinquent bills, if any;
2. The amount of any Company revenue loss attributable to said unauthorized use of service;
3. Expenses incurred by the Company in replacing or repairing the meter or other appliance, costs incurred in preparation of the bill, and costs outlined in paragraph b. above;
4. Reconnection fee applicable; and
5. A Cash deposit, the amount of which will not exceed the maximum amount determined in accordance with §V, paragraph 6 CONSUMER DEPOSITS.

22. GAS METER TEST BY CUSTOMER REQUEST - Any customer may request the Company to test its gas meter. The Company shall make the test as soon as possible after receipt of the request. If a request is made within one year after a previous request, the Company may require a deposit as follows:

Meter Rating	Deposit Amount
Residential	
All	$10.00
Non-Residential	
425 CFH* or less	$40.00
426 CFH to 1000 CFH	$40.00
Over 1000 CFH	$70.00

* Cubic feet per hour

The deposit shall be refunded only if the meter is found to have an unacceptable error, as defined in the Commission's regulations.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

In the case where a meter is replaced due to malfunction, a customer will be allowed one additional free meter test within 12 months, if requested by the customer.

23. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
    - Rate 102 - Residential Rate for Regular Employees
    - Rate 119 - Interruptible Gas Service Extension Policy
    - Rate 120 - Firm Gas Service Extension Policy
    - Rate 124 - New Installation, Replacement, Relocation and Repair of Gas Service Lines
    - Rate 134 - Rules and Policies for Implementing Master Metering Restrictions

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 3
Canceling Vol. 1 Original Sheet No. 3

RESIDENTIAL GAS SERVICE FOR REGULAR EMPLOYEES
Rate 102

The rate for residential gas service for regular employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly-owned subsidiaries of MDU Resources Group, Inc., shall be computed at the applicable rate, and the amount reduced by 33 1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular employee who has been continuously employed at least six months and is the principal support of the household in which employee resides, or is the spouse of the principal support.

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 19
Canceling Vol. 1 Original Sheet No. 19

INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide interruptible sales or interruptible transportation service to customers, except for customers served on Rate 66, is as follows:

1. Contribution

   a. Prior to construction, the customer shall contribute an amount equal to the total cost of construction including all gas main extensions, valves, tap setting and associated equipment, barricade, service line(s), regulators, meters (excluding remote data acquisition equipment), any required payments made by the Company to the transmission pipeline to accommodate the extensions, and other costs as adjusted for federal and state income taxes.

   b. The contribution shall be made by:

      i. A one-time payment prior to construction or,

      ii. The customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the total contribution required prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for a five-year period commencing at the plant in service date, and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists for the subject project, the surety or guarantor shall pay the Company for such contribution requirement, or

      iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

c. Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

d. Remote data acquisition equipment costs shall be subject to the terms and conditions specified in Transportation Service Rates 81 and 82.

2. Refund

a. If within the five-year period from the extension(s) in service date, the total of the customer's contribution and actual margin paid to the Company equals or exceeds the total present value of the revenue requirement associated with the extension, Company shall refund the amount exceeding the revenue requirement on the following basis:

i. Annually, beginning at the 2nd anniversary of the extension(s) in service date, the Company will refund to the customer, the amount exceeding the total present value of the revenue requirement at a rate of 50% of the current year margin associated with the customer's actual throughput.

ii. Customers who have posted a bond, letter of credit, or a written guarantee commitment will be notified of any reduction in surety or guarantee requirements based on the above calculation.

iii. No refunds will be made for amounts less than $25.00.

b. Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

c. No refund shall be made by the Company after the five-year refund period has expired, and in no case shall the refund, excluding interest, exceed the amount of contribution made by the customer.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 20
Canceling Vol. 1 1st Rev. Sheet No. 20

FIRM GAS SERVICE EXTENSION POLICY Rate 120

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm sales or firm transportation service to customers is as follows:

A. General Rules and Regulations Applicable to all Firm Service Extensions

1. An extension will be constructed without a contribution if the estimated capital expenditure is cost justified as defined in paragraph A.3.

2. The Company may require customer or developer cost participation if the estimated capital expenditure is not cost justified.

3. The extension will be considered cost justified if the calculated maximum allowable investment equals or exceeds the estimated capital expenditure using the following formula:

   Maximum Allowable Investment=

   (Annual Basic Service Charge + (Project Estimated 3rd Year Annual Dk x Distribution Delivery Charge))/Levelized Annual Revenue Requirement Factor

4. Cost of the extension shall include, if applicable, the gas main extension(s), valves, tap setting and associated equipment, barricade, service line(s), any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs excluding the distribution meter and regulator.

   The service line is that portion of the gas service extending from the main to the connection at the house regulator and/or meter.

5. Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer or the developer and Company.

6. A refund will be made only when there is a reduction in the amount of contribution required within a five-year period from the extension(s) in service date. Interest will be calculated annually by the Company on any refund

amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

No refund shall be made by Company after the five-year refund period and in no case shall the refund excluding interest, exceed the amount of the contribution.

7. The Company reserves the right to charge customer the cost associated with providing service to customer if service is not initiated within 12 months of such installation.

B. Customer Extensions

Cost participation for extensions where customers will be immediately available for service is as follows:

1. Contribution -

   a. When a contribution is required, the customer(s) shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with paragraph A.3.

   b. The contribution shall be made by:

      i. A one-time payment prior to construction, or

      ii. Payment of 25% of the contribution prior to construction and the balance in no more than twenty-four equal monthly installments. If customer discontinues service within the twenty-four month period, the balance will be due and payable upon discontinuance of service, or

      iii. Customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for the original five-year

term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement, or

iv. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

c. Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

d. If within the five-year period from the extension(s) in service date, the number of active customers and related volume exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment.

e. The recalculated contribution requirement shall be collected from the new applicant(s).

2. Refund -

a. The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25.00. Customers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

b. No refunds will be made until the new applicants begin taking service from the Company.

c. If the addition of new customers will increase the contribution required from existing customer(s), the extension will be considered a new extension and treated separately.

3. Incremental Expansion Surcharge -

a. The Company, in its sole discretion, may offer an Incremental Expansion Surcharge (Surcharge) to groups of customers requesting service totaling 10 or more when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. The contribution requirement to be collected under the Surcharge shall be the amount of the capital expenditure in excess of the Maximum Allowable Investment determined in accordance with paragraph A.3.

i. A minimum up-front payment of $100.00 will be collected from each customer who signs an agreement to participate in the expansion.

ii. For projects that are expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus $1.50 per dk.

iii. For projects that are not expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus a commodity charge designed to provide recovery of the contribution requirement.

b. The Surcharge shall remain in effect until the net present value of the contribution requirement, calculated using a discount rate equal to the overall rate of return authorized in the last rate case, is collected.

c. The Surcharge shall apply to all customers connecting to natural gas service within the expansion area until the contribution requirement is satisfied.

d. The net present value of the Surcharge will be treated as a contribution-in-aid of construction for accounting purposes.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

FIRM GAS SERVICE EXTENSION POLICY Rate 120

C. Developer Extensions

Cost participation may be required for extensions such as a subdivision or mobile home court, in which a developer is installing roads, utilities, etc., before housing is built.

1. Contribution -

a. When a contribution is required, the developer shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with paragraph A.3.

b. The contribution shall be made by:

i. A one-time payment prior to construction, or

ii. Developer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or a written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists in the subject project based on a recalculated maximum expenditure, the surety shall reimburse the Company for such recalculated contribution requirement, or

iii. Developer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, 3) interest will be charged at the Company's incremental weighted cost of capital.

c. Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

FIRM GAS SERVICE EXTENSION POLICY Rate 120

2. Refund -

   a. If within the five-year period from the extension(s) in service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment. Such recalculation shall be done annually based upon the anniversary of the extension(s) in service date.

   b. The Company will refund to the developer the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25.00. Developers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

   c. If the addition of new customer(s) will increase the contribution required from the developer, the extension will be considered a new extension and treated separately.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule

SD P.U.C. Section No. 5
Original Sheet No. 24
Canceling Vol. 1 Original Sheet No. 24

NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

1. The Company will install, at its expense, a service line extending from the main to the connection at the premise regulator and/or meter for all customers connected on and after (effective date of tariff) and all replacement service lines installed on and after (effective date of tariff). The service line installed by the Company will remain the Company's property.

2. A non-refundable contribution may be required for that portion of the service line cost not supported by the expected or actual connected load. The contribution requirement will be determined based on minimum footage allowances determined annually taking into account the maximum allowable investment defined in Rate 120 and the statewide average installed per foot cost. The Company reserves the right to charge customer the total cost of the installed service line if service is not initiated within 12 months of such installation.

3. The portion of the service line not cost justified shall be charged to the customer on the basis of direct costs to the Company. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply.

4. Where service line location changes are required due to building encroachments (a building is being constructed or is already located over a service line, etc.) or due to a customer request to move a service line, the customer shall be charged on the basis of direct costs incurred by the Company.

5. Whenever a service line is damaged by the customer or someone under the employ of the customer necessitating the service line to be either repaired or replaced in whole or in substantial part, such work shall be charged for on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

6. Service line changes necessary to increase the size and capacity of an existing service line because of increased demand shall be treated in accordance with paragraph 2 above.

Date Filed: December 30, 2002
Effective Date: Service Rendered on and after December 2, 2003
Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs
Implemented December 4, 2003
Docket No.: NG02-011

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 34
Canceling Vol. 1 Original Sheet No. 34

RULES AND POLICIES FOR IMPLEMENTING MASTER METERING RESTRICTIONS Rate 134

Section 1. Definitions

(a) "Multiple occupancy building" shall mean any building which contains more than one residential or commercial unit.

(b) "New multiple occupancy building" shall mean any building for which the physical labor involved in the erection of such building started on or after June 13, 1980.

(c) "Existing multiple occupancy building" shall mean any building for which the physical labor involved in the erection of such building started before June 13, 1980.

(d) "Mobile home court or trailer park" shall mean any such mobile home courts or trailer parks in which residence is predominantly either permanent or long term, and shall not include mobile home courts or trailer parks in which residency is highly transient, such as campgrounds for recreational vehicles or trailers used for recreation or vacations.

(e) "New mobile home courts or trailer parks" shall mean such courts or parks, for which the physical labor involved in the construction commenced on or after June 13, 1980.

(f) "Existing mobile home courts or trailer parks" shall mean such courts or parks, for which the physical labor involved in the construction commenced before June 13, 1980.

(g) "Master metered service" shall mean gas service provided to more than one residential or commercial unit through a single meter.

(h) "Individually metered service" shall mean gas service provided to one residential or commercial unit through a single meter which serves that unit only and no other unit.

(i) "Company" shall mean Montana-Dakota Utilities Co.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 34.1
Canceling Vol.1 Original Sheet No. 34.1

RULES AND POLICIES FOR IMPLEMENTING MASTER METERING RESTRICTIONS Rate 134

Section 2. Applicability

Natural gas service to new multiple occupancy buildings and mobile home courts or trailer parks shall be provided as individually metered service only unless specifically exempted by one or more of the provisions contained in Section 3 below.

Section 3. Exceptions

(a) Residential multiple occupancy buildings consisting of no more than two units, one of which is owner occupied, may be served by one master meter.

(b) The following multiple occupancy buildings or facilities may be served by master meter:

(i) Hospitals
(ii) Nursing or convalescent homes
(iii) Transient hotels or motels
(iv) Dormitories
(v) Campgrounds
(vi) Residential facilities of a transient nature

(c) Existing multiple occupancy buildings (construction of which commenced before June 13, 1980) which are presently receiving master metered gas service may continue to be served on a master metered basis.

(d) Master metered gas service provided for central heating or cooling systems, central ventilating systems or for central hot water heating systems.

(e) Service to multiple occupancy buildings constructed, owned or operated with funds appropriated through the U.S. Department of Housing and Urban Development, or any other federal or state government agency, shall be served by individual meters. If such individual metering requirement is inconsistent with regulations promulgated by such department or agency, service on a master metered basis is allowed.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 34.2
Canceling Vol. 1 Original Sheet No. 34.2

RULES AND POLICIES FOR IMPLEMENTING MASTER METERING RESTRICTIONS Rate 134

(f) Existing mobile home courts and trailer parks may continue to be served on a master metered basis, subject to Section 5 of this tariff.

Section 4. Remodeling and Renovation

Where there is an existing multiple occupancy building receiving master metered gas service which is substantially remodeled or renovated for continued use as a multiple occupancy building, for which the physical labor for remodeling or renovation is begun after June 13, 1980, gas service to the units after completion of the remodeling or renovation shall be on an individual metered basis, unless the owner of such building demonstrates to the South Dakota Public Utilities Commission that such conversion would be impractical, uneconomical or unfeasible, and the owner of such building provides the Company with evidence of the South Dakota Public Utilities Commission decision.

Section 5. Owner or Operator Charge for Gas Service

(a) Gas service to an existing master metered multiple occupancy building, if not otherwise prohibited by this tariff, shall be provided only upon condition that charges for gas made by the owner or operator to each tenant or occupant shall be equal to each tenant's or occupant's pro rata share of the total amount charged to the owner or operator by the Company in proportion to the ratio of the total square foot floor area of the building.

(b) Gas service to an existing master metered mobile home court or trailer park shall be provided only upon condition that charges for gas made by the owner or operator of such court or park to each tenant or occupant shall be equal to such tenant's or occupant's pro rata share of the total amount charged to the owner by the Company in proportion to the ratio of the square foot floor area of each tenant's or occupant's unit to the total square foot floor area of the mobile home court or trailer park.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 34.3
Canceling Vol. 1 Original Sheet No. 34.3

RULES AND POLICIES FOR IMPLEMENTING MASTER METERING RESTRICTIONS Rate 134

Section 6. Variation

Any variation from the above rules will only be made after the owner or operator provides evidence of South Dakota Public Utilities Commission approval of such variation.

All other rules and regulations of Montana-Dakota which govern gas service in South Dakota and which do not conflict with the provisions of this rule shall apply to gas service provided to new and existing buildings which are subject to this rule. The customer is responsible for ascertaining and complying with all applicable rules and regulations of any governmental authority having jurisdiction over the subject matter of this rule.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 1
CONSUMER'S DEPOSIT RECEIPT Canceling Vol. 1 4th Rev. Sheet No. 1

CONSUMER'S DEPOSIT RECEIPT

Received of: Account

Date

Deposit Nbr

Deposit Amount

Service Address
135 WESTGATE RD LOT 150
BOX ELDER SD 57719

A deposit of is received as security for the payment of any amount which may become due Montana-Dakota Utilities Co., for utility services and is not to be considered a payment on account. If at any time a bill of the customer is not paid within 22 days after date of presentation, the deposit may, at the option of the company, be applied to the account thereof.

This deposit will be refunded, with interest, provided all bills have been paid in full and service is no longer desired or when customer has established satisfactory credit in accordance with the public service or utility commission rules. This deposit will bear interest at the rate of 7.00 % or at a rate equal to the rate required by the public service or utilities commission on an annual basis. Interest shall accrue from the date payment is made on the deposit until the day the deposit is refunded or upon discontinuance of service. Interest shall be credited to the customer's account annually during the month of December. This statement shall constitute a receipt of said deposit and shall not be transferable.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 2
Canceling Vol. 1 Original Sheet No. 2.1

NEW CUSTOMER APPLICATION CARD – GENERAL SERVICE

NEW CUSTOMER APPLICATION CARD - GENERAL SERVICE

front

20902(6-81) (Rev.11/87) MONTANA-DAKOTA UTILITIES CO.
NEW CUSTOMER APPLICATION CARD – GENERAL SERVICE

Business Name: _____ Acct. No.: _____
Service Address: _____
Mailing Address: *(If different)* _____
Business Phone: _____ Home Phone: _____
Type of Business Activity: _____
Owner of Building: _____ (Name) _____ (Address) _____ (Phone)
Type of Service Requested: Electric ☒ Gas ☐ Date Service To Begin: __/__/__
Previous Address: _____ (Street) _____ (City) _____ (State)
Gen. Serv. Cust. of MDU at Prev. Address: Yes ☐ No☐ _____ (When) _____ (Where)
Legal Status: Corporation ☐; Partnership ☐; Sole Proprietorship☐; _____ (Other)
Name, Address and Phone of Owners, Partners, Officers or Local Representatives:
(Name) (Address) (Phone)
_____
_____
_____

back

Applicant whose signature appears below hereby grants permission to MDU to enter applicant's premises at all reasonable times for the purpose of installing, connecting, reading, inspecting, operating, disconnecting or removing the company pipes, wires, meters or other equipment and warrants that applicant has authority to grant this permission.

Date: _____ Signature: _____

Title: _____

DO NOT WRITE BELOW – FOR OFFICE USE ONLY

Identification: Current Driver's License—State_____ No._____

OR Social Security Number: _____

Deposit or Security Required: Yes ☐ No ☒ Amt. _____ Date: __/__/__

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 3
Canceling Vol. 1 2nd Rev. Sheet No. 3

GAS METER ORDER

MONTANA-DAKOTA UTILITIES CO.
GAS METER ORDER

ORDER RECEIVED BY:	HOW RECEIVED: • TELEPHONE ☐ • IN PERSON ☐ • LETTER ☐	TIME:	NAME OF PERSON PLACING ORDER:	DATE:	TOWN:	ACCOUNT NO.:
CONNECT METER FOR:			DISCONNECT METER FOR:			
TELEPHONE NO.:	MAILING ADDRESS (AND IF DIFFERENT) SERVICE ADDRESS:					CITY LIMITS: IN ☐ OUT ☐
CUSTOMER CLASS IN:	RATE:	SERVICE REQUESTED: GAS ONLY ☐ GAS & ELECTRIC ☐		PREVIOUS ADDRESS:		
DEPOSIT: NO. $	NO DEPOSIT REQUIRED: JOB OWNER REFERENCES			FORWARDING ADDRESS:		

METER IN

COMPANY NO.:	MANUF.:	SERIAL NUMBER:	SIZE:
DATE:	DIALS:	STANDARD READING:	GAUGE PRESSURE: LBS. ____ OZS. ____

METER LOCATION:
OUTSIDE ☐ BASEMENT ☐ MAIN FLOOR ☐ UPSTAIRS ☐ GARAGE ☐ READ OUT ☐

THE FOLLOWING NEEDS TO BE FILLED IN WHEN INTERGRATING INSTRUMENTS OR PRESSURE FACTORS.

ATMOS. PRESS.	PRESSURE FACTOR	FACTORED METER Yes ☐ No ☐
INSTRUMENT	CORRECTING TO CCF 10 ☐ 100 ☐ 1000 ☐	CORRECTED READING
DIALS	CORRECTING TO CCF 10 ☐ 100 ☐ 1000 ☐	UNCORRECTED READING
WORK DONE BY:		PREMISE TIME:

REGULATORS: 1ST _____ 2ND _____
ORIFICE SIZE: _____
PILOT INSPECT ☐ Yes ☐ No
INSULATOR INSPECT ☐ Yes ☐ No
DISTRIBUTION ACCT. ☐ Yes ☐ No
TRANSMISSION ACCT. ☐ Yes ☐ No
DELIVERY POINT ID: _____
LINE TAP: _____
DELIVERY USE: _____

METER OUT

DATE:	COMPANY NO.:	SERIAL NO.:
STANDARD READING:	UNCORRECTED READING:	

☐ METER EXCHANGE* ☐ METER REMOVED*
☐ SEALED AT METER STOP ☐ CUT OUT AT METER
☐ SEALED AT RISER STOP ☐ SERVICE LEFT ON

*REASON METER REMOVED
☐ RANDOM TESTING ☐ DAMAGED
☐ PERIODIC TESTING ☐ NON REGISTER
☐ TEST FAILURE LIST ☐ OTHER

REMARKS:

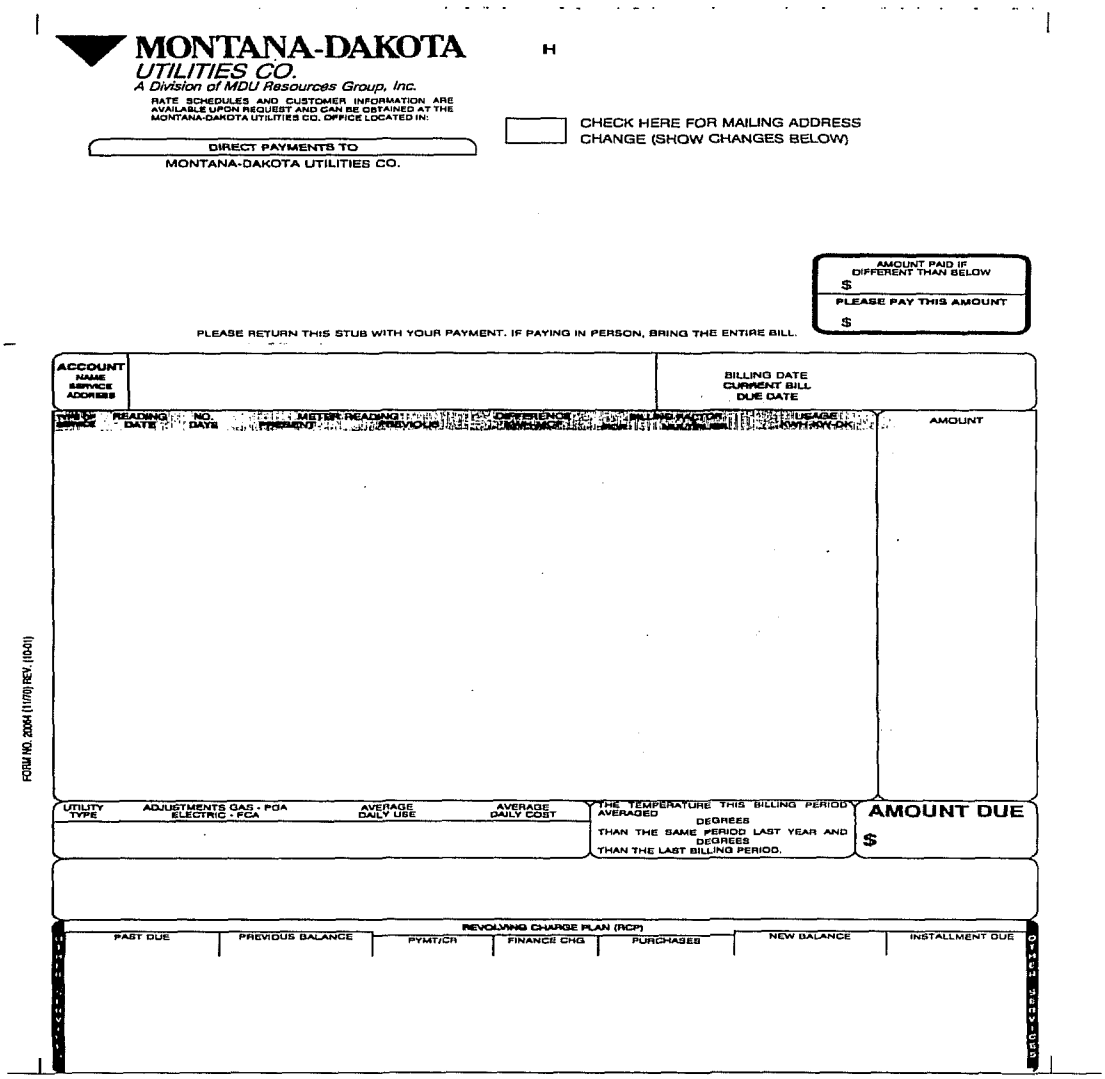
Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 4
Canceling Vol. 1 6th Rev. Sheet No. 5

STANDARD CUSTOMER BILL

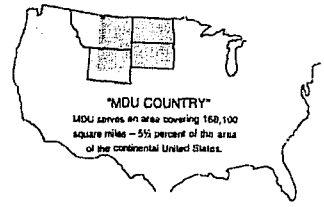

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
RATE SCHEDULES AND CUSTOMER INFORMATION ARE AVAILABLE UPON REQUEST AND CAN BE OBTAINED AT THE MONTANA-DAKOTA UTILITIES CO. OFFICE LOCATED IN:
DIRECT PAYMENTS TO
MONTANA-DAKOTA UTILITIES CO.
H
CHECK HERE FOR MAILING ADDRESS CHANGE (SHOW CHANGES BELOW)
AMOUNT PAID IF DIFFERENT THAN BELOW
$
PLEASE PAY THIS AMOUNT
$
PLEASE RETURN THIS STUB WITH YOUR PAYMENT. IF PAYING IN PERSON, BRING THE ENTIRE BILL.
ACCOUNT NAME SERVICE ADDRESS
BILLING DATE
CURRENT BILL DUE DATE
TYPE OF SERVICE
READING DATE
NO. DAYS
METER READING PRESENT
METER READING PREVIOUS
DIFFERENCE
BILLING FACTOR
USAGE THIS PERIOD
AMOUNT
FORM NO. 20004 (11/10) REV. (10-01)
UTILITY TYPE
ADJUSTMENTS GAS - PGA ELECTRIC - FCA
AVERAGE DAILY USE
AVERAGE DAILY COST
THE TEMPERATURE THIS BILLING PERIOD AVERAGED
DEGREES
THAN THE SAME PERIOD LAST YEAR AND
DEGREES
THAN THE LAST BILLING PERIOD.
AMOUNT DUE
$
REVOLVING CHARGE PLAN (RCP)
PAST DUE
PREVIOUS BALANCE
PYMT/CR
FINANCE CHG
PURCHASES
NEW BALANCE
INSTALLMENT DUE
OTHER SERVICES

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Director of Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

STANDARD CUSTOMER BILL



MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve℠

BALANCED BILLING . . . Balanced Billing is MDU's voluntary plan to help you budget your utility bills. Because of severe weather in our northern climate, utility bills may fluctuate widely between winter and other seasons.

With Balanced Billing you can reduce the impact of higher winter bills by averaging them with those during lower fuel usage months. It gives you more level bills throughout the year. It puts you in control. Remember, there's no charge for this service.

You can sign up for Balanced Billing by a telephone call to 1-800-MDU-FAST (1-800-638-3278).

THERM BILLING . . . **Mcf Conversion to Therms:** Your gas bill is computed using a standard measure of heat energy called a "therm". The thousands of cubic feet (Mcf) used (as measured by your gas meter) are converted to decatherms by multiplying the Mcf's by a factor which is based on heat content and atmospheric pressure of the gas delivered to your premise. Such heat content can vary each month. This conversion ensures that all customers are charged accurately for the heat value of the gas they use.

CODES AND DEFINITIONS . . . **FCA/PGA Fuel Cost Adjustment and Purchased Gas Adjustment:** The adjustments shown on your bill are shown per kilowatt hour or per decatherm. These adjustments reflect changes in the cost of fuels and natural gas purchased by MDU. MDU receives no profit from these charges.

Dk - Decatherm: A measure of heat energy. One decatherm contains ten therms or one million British thermal units (Btu's).

Btu - British thermal units: Quantity of heat required to raise the temperature of one pound of water one degree fahrenheit.

Mcf - Thousand Cubic Feet: The basic measure of the amount of natural gas used.

TF - Thermal Factor: Multiplier used to convert Mcf to decatherms (dk's) by heating value and delivery pressure.

Kwh - Kilowatt-Hour: The basic unit for measuring the use of electricity. It is the amount of electricity used by ten 100-watt light bulbs left on for one hour.

REVOLVING CHARGE PLAN . . . **RCP - Your FINANCE CHARGE** is computed at a **DAILY RATE OF .0004932**, which is a corresponding **ANNUAL PERCENTAGE RATE OF 18%**. To avoid additional finance charges, pay by the due date shown on the other side of this bill. In case of errors or questions about your bill, write us at P.O. Box 5600, Bismarck, North Dakota 58506-5600.

AE - All Electric
AI - Alternate Energy Based Interruptible Gas
AMT - Amount
APR - Annual Percentage Rate
AU - All Electric Underground
CG - Commercial Gas
CHG - Charge
CJ - Conjunctive
CR or (-) - Credit
DE - Demand
E - Estimated Meter Read
EH - Electric Heating
FE - Firm Energy
FG - Feed Grinding
FS - Firm Gas Service
FT - Firm Gas Transportation
GE - General Thermal Energy Storage
GG - General Gas Service
GS - General Dual Fuel Space Heating
GT - General Electric Time-Of-Day
GV - Government
IG - Interruptible General Gas
IL - Interruptible Large Power
IN - Industrial Gas
IP - Irrigation Power
IR - Irrigation Time-Of-Day
IT - Industrial Time-Of-Day
KV - Kvar Penalty
KW - Kilowatt/Demand
LE - Large General Electric Standby and Supplementary
LG - Large General Electric
LI - Large Interruptible General Gas
LP - Long-Term Power
LS - Large Power Standby
LT - Large General Ele Time-Of-Day
MC - Meter Constant
ME - Miscellaneous Electric
ML - Municipal Lighting
MP - Municipal Pumping
NB - Net Billing Option
NF - Non-Firm Non-Time Differentiated
NT - Non-Firm Time Differentiated
OG - Optional Seasonal General Gas
OS - Optional Seasonal Residential Gas
P - Pre-Rated Amount
PF - Atmospheric Pressure Factor
PG - Parallel Generation
PL - Private Lighting
PR - Propane Service
PT - Power Purchase Time Differentiated
PYMT - Payment
RCP - Revolving Charge Plan
RE - Residential Electric
RF - Residual Fuel-Oil Based
RG - Residential Gas
RS - Residential Dual Fuel Space Heating
RT - Residential TimeDay
SD - Special General Controlled Electric
SE - Small General Electric Standby and Supplementary
SG - Small General Electric
SI - Small Interruptible General Gas
SL - Street Lighting
SM - Small Municipal Electric
SR - Special Residential Controlled Electric
SS - Standby Gas
ST - Small General Ele Time-Of-Day
SU - Supercompressibility
TG - General Transportation of Gas
TI - Industrial Transportation of Gas
TR - Residential Thermal Energy Storage
UE - Underground Electric
UW - Uncontrolled Water

Date Filed: December 30, 2002
Effective Date: Service Rendered on and after December 2, 2003
Issued By: Donald R. Ball
Director of Regulatory Affairs
Implemented December 4, 2003
Docket No.: NG02-011

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 5
Canceling Vol. 1 4th Rev. Sheet No. 6

DISCONNECT NOTICE

13 17 342

MONTANA-DAKOTA UTILITIES CO

R6

Account Number: 658 34

DISCONNECT NOTICE

WE WANT TO CONTINUE OUR DEPENDABLE SERVICE TO YOU,
OUR VALUED CUSTOMER, BUT YOU MUST TAKE ACTION NOW.

Service Address:

Payment of your service account is now past due. Your service will be disconnected on unless your past due amount is paid in full or satisfactory arrangements are made before this date. If service is disconnected, payment in full and a reconnect fee of $12.72 to restore service during normal working hours, plus a deposit or additional deposit of $0.00 will be required before service is restored.

PLEASE CONTACT US NOW TO AVOID ANY INCONVENIENCE

Date:

	PAST DUE	CURRENT	ACCT BALANCE
UTILITY:	$	$	$
DEPOSIT:	$0.00	$0.00	$0.00

Direct inquiries to:
MONTANA-DAKOTA UTILITIES CO
PO BOX 1060
RAPID CITY SD 57709
1 605 342 0187

Direct unresolved complaints to:
SD PUBLIC UTILITIES COMMISSION
500 E CAPITOL
PIERRE SD 57501
1 800 332 1782

Date Filed: December 30, 2002

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.: NG02-011

Effective Date: Service Rendered on and after December 2, 2003

Implemented December 4, 2003

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 6
Canceling Vol. 1 1st Rev. Sheet No. 7

APPLICATION FOR INTERRUPTIBLE NATURAL GAS SERVICE

20474(7-68)
(Rev. 9/85)

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

APPLICATION FOR INTERRUPTIBLE NATURAL GAS SERVICE

Dated: _____

The undersigned hereby makes application to Montana-Dakota Utilities Co., hereinafter referred to as the Company, for interruptible natural gas service, at the location shown below.

(A) Application is a non-residential retail gas customer of the Company and in order to secure a rate differential as provided under the terms and conditions of the Company's Rate Schedule _____. Applicant agrees to discontinue use of natural gas immediately upon notice from the Company, on natural gas equipment having alternate fuel capability or on such equipment which qualifies customer for interruptible service. Applicant agrees not to resume the use of natural gas during periods of interruption until informed that it may do so by the Company.

(B) During periods of interruption, applicant may continue the use of natural gas on firm usage equipment as listed below.

(C) Company's rates and services are subject to regulation and Applicant will be bound by any changes as approved by the applicable regulatory authorities.

INTERRUPTIBLE EQUIPMENT

Type & No. of Units	Input (cfh)	Standby Fuel	Peak Day Usage (MCF)

FIRM USAGE EQUIPMENT

Type & No. of Units	Input (cfh)	Peak Day Usage (MCF)

APPLICANT: _____ BY: _____

ADDRESS: _____

CITY AND STATE: _____

MDU CUSTOMER ACCOUNT NO.: _____

APPROVED:

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

By: _____
(Division Manager)

DISTRIBUTION:
1 Copy to Division Gas Superintendent
1 Copy to Division Manager
1 Copy to Division Accounting Administrator
1 Copy to Gas Dispatching Superintendent (WBI-Glendive)
1 Copy to Customer

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 7
Canceling Original Sheet No. 7

CUSTOMER INFORMATION BOOKLET

CUSTOMER INFORMATION BOOKLET

Date Filed:	May 18, 2004	**Effective Date:**	January 6, 2004
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		
Docket No.:	GE03-001		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 7.1
Canceling Original Sheet No. 7.1

CUSTOMER INFORMATION BOOKLET

CUSTOMER INFORMATION BOOKLET

ADDITIONAL CUSTOMER INFORMATION FOR SOUTH DAKOTA CUSTOMERS

Montana-Dakota Utilities Co. (Montana-Dakota) is regulated by the South Dakota Public Utilities Commission whose duties were expanded in 1975 to include regulation of natural gas and electric utilities. It is the commission's duty to oversee rates and services of all investor owned gas and electric utilities in the state.

Montana-Dakota feels it is important that you are satisfied with your natural gas or electric service. However, sometimes a question, misunderstanding or complaint may develop. If it does, please let us know. Our employees are trained to help you.

Montana-Dakota will make a full and prompt investigation of all written complaints received. Please direct all written complaints to the Montana-Dakota office that appears on your utility bill.

DISPUTES

Whenever a customer advises Montana-Dakota, before the disconnection of natural gas or electric service, that any part of the billing, charges or service is in dispute, Montana-Dakota shall:

1. Investigate the dispute promptly.
2. Advise the customer of the investigation and its result.
3. Attempt to resolve the dispute.
4. Withhold disconnection of service providing the customer pays the undisputed portion of the bill.

If the dispute is not resolved Montana-Dakota must notify the customer that the customer has the right to appeal to the South Dakota Public Utilities Commission within ten (10) business days after the disconnection notice was sent for resolution of the dispute.

The commission is available for consultation, you may write or call:

South Dakota Public Utilities Commission
Capitol Building
Pierre, South Dakota 57501
1-605-773-3201

CREDIT AND DEPOSIT POLICIES

Montana-Dakota's deposit policy is predicated upon the credit risk of the individual as evidenced by past energy purchases without regard to the collective credit reputation of the area in which he or she lives and without regard to any of the traditional means for establishing credit such as home ownership or friendly relations with a bank.

This credit and deposit policy is administered without discrimination in regard to race, color, creed, religion, sex, ancestry, marital status, age or national origin.

Montana-Dakota will not require a deposit or guarantee from any new or present customers who have established good credit. Montana-Dakota will determine the credit standing of an applicant for service by referring to information about the applicant's prior energy usage and bill paying habits if the applicant has had service before. In the case of unknown credit, traditional means of credit rating can be supplied by the applicant.

A customer who has had one or more disconnections of service in the last year, or three or more disconnection notices in the last year, or has an undisputed outstanding debt with Montana-Dakota may be asked to reestablish credit through one of the following methods:

1. Make a cash deposit not to exceed one-sixth (1/6) of the estimated annual bill. Deposits will earn seven percent (7%) simple interest per year from the date of the deposit to the date of refund or disconnection.
2. Provide a guarantor (residential only).
3. Be placed on an early payments list wherein the customer agrees to pay the bill for utility services within five (5) business days after it is received.
4. A non-residential customer may also provide a letter of credit, post a surety bond, or negotiate another option with the Company.

An existing customer will be given notice of not less than fifteen (15) days that a deposit, guarantor, or early payment is required.

REFUSAL AND DISCONNECTION POLICIES

Naturally, if your utility bill is not paid within a reasonable length of time, you cannot expect to continue to receive natural gas or electric service from Montana-Dakota.

We do not like to disconnect or refuse service to a customer, but sometimes it must be done. You will be notified before such action is taken if the reason is:

1. Non-payment of your utility service bill (after consumer deposit and earned interest, if any, have been applied to the outstanding bill).
2. You have failed to pay a required deposit or meet the credit requirements.
3. You have violated Montana-Dakota's rules on file with the South Dakota Public Utilities Commission. These rules are available for your inspection at the Montana-Dakota office noted on your utility bill.
4. You have broken the terms of the contract for service with Montana-Dakota or have failed to furnish those things necessary to obtain utility service.
5. You have failed to allow Montana-Dakota employees access to company equipment located on your premise for meter reading, inspection, maintenance, replacement of equipment or to conduct investigations for hazardous conditions.
6. Unauthorized use of Montana-Dakota's equipment or tampering with Montana-Dakota's service equipment.

The following is a list of conditions, all of which must occur, before you will be disconnected for non-payment of a bill:

1. A customer may be receiving service from Montana-Dakota at more than one location. Only the service for which the bill is delinquent can be disconnected.
2. Bills are due when received. Bills become delinquent twenty-two (22) days after billing transmittal date. This period may be shortened if the customer's name is on the early payments list. This time period may be waived in cases of fraud, illegal use or when it is clearly indicated that the customer is preparing to leave. Montana-Dakota will send you a written notice giving you an additional ten (10) days in which to pay the bill to avoid disconnection.
3. If this is the customer's first disconnection notice, the customer will receive an additional personal notice by either telephone, visit or certified mail. Both written notice and personal notice shall contain a statement of the customer's right to appeal and where to appeal.
4. The customer, if he or she claims inability to pay or extenuating circumstances, is unwilling to enter into a reasonable agreement with Montana-Dakota to pay the service bill.
5. No bona fide or just dispute concerning the bill exists. A dispute shall not be defined as bona fide and just if the customer does not pay the undisputed portion of the bill and does not, after notice of their right to do so, contact the commission with the unresolved dispute within ten (10) working days after the disconnection notice was sent.

Natural gas or electric service shall not be disconnected on any Friday, Saturday, Sunday or legal holiday, or at any time when Montana-Dakota's business offices are not open to the public.

The customer can pay a delinquent bill at the last minute to avoid disconnection. Montana-Dakota's representative who comes to disconnect the service can also accept last-minute payments.

In a landlord-tenant situation, where the meter is in the landlord's name, Montana-Dakota will not disconnect the utility service until the tenant has been offered the opportunity to put the natural gas service or electric service in their own name and the tenant has turned down this offer. Montana-Dakota will not ask the tenant to pay any outstanding bills or other charges owed by the landlord.

The disconnection of utility services during cold weather could cause a threat to health and life. Montana-Dakota shall not disconnect residential utility service from Nov. 1 to March 31 without adding an additional 30 days to the normal disconnection date. Montana-Dakota shall notify the customer before the normal disconnection date that the customer has an additional thirty (30) days until disconnection of service.

If disconnection of utility services will aggravate an existing medical emergency of the customer, a member of his family or other permanent resident of the premise, Montana-Dakota will postpone disconnection of services for 30 days from the date of a physician's certificate or notice from a public health or social services official that such a medical emergency exists. This extension is limited to a single thirty (30) day period.

INSUFFICIENT REASONS FOR REFUSAL

Montana-Dakota cannot refuse to serve a person:

1. Who will not pay a debt to another utility, or a debt for another class of service, or a debt for other bills not based on filed rates or charges;
2. For non-payment of a bill for which he or she is guarantor;
3. Asking for service in a dwelling where the former occupant was delinquent;
4. Who is living with someone that is in debt to Montana-Dakota in an attempt to force payment of that bill, except when that person, even though not personally liable to Montana-Dakota, is trying to get service back to the indebted household and no attempts are being made to pay the debt of that household.

This pamphlet is a summary of Montana-Dakota's customer rules. A complete listing of Montana-Dakota customer rules and South Dakota Public Utilities Commission rules, regulations and rate schedules are available for your inspection at the Montana-Dakota office noted on your utility bill. Your billing, payment and deposit records are also available to you for inspection. Montana-Dakota will furnish additional information as you may reasonably request.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 8
Canceling Vol. 1 Original Sheet No. 9

DISCONTINUANCE NOTICE FOR UNAUTHORIZED USE OF SERVICE

DISCONTINUANCE NOTICE FOR UNAUTHORIZED USE OF SERVICE

20614(11-81)
(Rev. 2/88)

MONTANA-DAKOTA UTILITIES CO.
DISCONTINUANCE NOTICE

NOTICE TO CUSTOMER:

Today we inspected your gas/electric service installation. This inspection has revealed that you are obtaining unauthorized gas/electric service at the address shown below. Under rules and regulations filed with, and approved by, the Public Utility Commission of _____, service can be terminated because of this irregularity. To avoid discontinuance of service bring this card to our office, no later than _____, at the address shown below, and we will discuss the conditions under which your gas/electric service will not be interrupted.

MONTANA-DAKOTA UTILITIES CO.

Address: _____

_____

Telephone No.: _____

Date: _____

Customer: _____

Address: _____

_____

Meter No.: _____

Employee: _____

WHITE — Customer

YELLOW — File

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 9
Canceling Vol. 1 Original Sheet No. 12

THIRD PARTY NOTICE

Would you like to be a designated Third Party?

Montana-Dakota Utilities Co. (MDU) has a program available called "Third Party Notice." The purpose of the program is to help avoid any hardship which could result from disconnection of service by alerting a third party to such action in advance. This voluntary program would most benefit customers who are ill or elderly and live alone.

Under the "Third Party Notice" program, if it would be necessary to disconnect service due to nonpayment of past due bills, the customer as well as the designated third party would be notified prior to the disconnect date. The third party would then have the right to contact MDU and declare the customer's inability to pay and enter into a payment arrangement for the customer.

A third party can be a friend, relative, church or any community agency. The designated third party will have the right to receive and provide information regarding the customer's personal circumstances. **Please talk with this third party before you tell MDU this person will help you.** The third party ***will not*** be responsible for payment of the customer's bill.

If your personal circumstances require that a third party be aware of a potential disconnection of your utility service, please complete and detach the form provided and return it to MDU as soon as possible. If you know of someone who might benefit from third party notification, please let them know of it. As individual circumstances frequently may change, Third Party Notices are valid for **one year** only, and an annual renewal is required. Please complete the form and return it to MDU – even if you have done so before.

For information of public agencies and community organizations which may be able to assist in payment of winter utility bills, please call the telephone number found on your utility bill or write to the MDU office address, also found on your utility bill.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

Request For A Third Party Notification (To be valid through November, 2003)

Customer Name: (Please print)

_____

Address: _____

City: _____ State: _____ Zip: _____

Telephone Number: _____

Account Number from Bill: _____

MONTANA-DAKOTA UTILITIES CO. has my permission to provide information to and accept information from the party named below.

Customer Signature: _____

Date: _____

Name of Third Party to be Notified: (Please print)

_____

Address: _____

City: _____ State: _____ Zip: _____

Telephone Number: _____

MONTANA-DAKOTA UTILITIES CO. will make every effort to send a copy of the Notice of Proposed Disconnection to the party specified. The customer making the request understands that MDU assumes no liability for failure of third party to receive or act upon said Notice.

Complete all information and return to the MDU office address found on your bill as soon as possible.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 10
Canceling Vol. 1 Original Sheet No. 13

DEFERRED INSTALLMENT AGREEMENT FORM

20292111-801
(Rev. 4/87)

DEFERRED INSTALLMENT AGREEMENT FORM
MONTANA-DAKOTA UTILITIES CO.
DEFERRED INSTALLMENT AGREEMENT FORM

Name: _____ Date: _____
Address: _____ Delinquent Bill: $ _____
_____ Current Bill: $ _____
Account Number: _____ Total Bill: $ _____
Security Deposit: $ _____
TOTAL: $ _____

PAYMENT ARRANGEMENT

Amount	Due Date	Date Paid
$ _____	_____	_____
$ _____	_____	_____
$ _____	_____	_____
$ _____	_____	_____
$ _____	_____	_____
$ _____	_____	_____

* In addition to these arrangements, the current monthly bill is to be paid.

Other: _____
_____
_____

FAILURE TO COMPLY WITH THIS AGREEMENT WILL RESULT IN THE COMPANY TAKING ACTION TO DISCONTINUE YOUR UTILITY SERVICE.

Customer Signature: _____ Date: _____
(Customer signature is required even if submitted by Third Party)

Third Party Signature: _____ Date: _____

Name of Utility Representative: _____ Date: _____

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
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Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 11
Canceling Vol. 1 1st Rev. Sheet No. 14

AGREEMENT BY PROPERTY OWNER OR AGENT TO PAY UTILITY BILLS DURING PERIODS WHEN PROPERTY IS UNOCCUPIED

AGREEMENT BY PROPERTY OWNER OR AGENT TO PAY
UTILITY BILLS DURING PERIODS WHEN PROPERTY IS UNOCCUPIED

Rev. 11/90

MONTANA-DAKOTA UTILITIES CO.
AGREEMENT BY PROPERTY OWNER OR AGENT TO PAY UTILITY BILLS DURING PERIODS WHEN PROPERTY IS UNOCCUPIED

The undersigned is the owner, or the owner's agent, of a house or apartment at:

_____
(Street Address)

_____
(City and State)

It is my desire that Montana-Dakota Utilities Co. leave its natural gas and/or electric service turned on even if the tenant or occupant, in whose name the service is metered, requests that such service be discontinued.

In consideration of Montana-Dakota Utilities Co. doing so, I agree to pay promptly every service bill tendered for usage during the period of discontinuance of service by a tenant or occupant.

In case I sell the premises, I agree to notify Montana-Dakota Utilities Co. in writing and until Montana-Dakota Utilities Co. receives such notification, I will assume liability as provided above. I also agree to notify Montana-Dakota in writing if I change my address.

Montana-Dakota Utilities Co. expressly reserves the right to disconnect service to a tenant pursuant to the rules and regulations of the applicable regulatory agency. It is agreed by and between Montana-Dakota Utilities Co. and the undersigned that in cases where a tenant is disconnected at the Company's option, the Company will use its best efforts to notify me of the disconnection.

_____, 19____ Signed: _____

(PLEASE PRINT OR TYPE INFORMATION BELOW)

_____
(Name)

_____
(Mailing Address)

_____
(City) (State) (Zip Code)

_____
(Area Code – Telephone Number)

WHITE – District Office Copy YELLOW – Customer Copy

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
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Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 12
Canceling Vol. 1 Original Sheet No. 15

FORM ADVISING PROPERTY OWNER TENANT IS VACATING PREMISES AND SERVICE HAS BEEN CONNECTED IN PROPERTY OWNER'S NAME PER AN AGREEMENT

FORM ADVISING PROPERTY OWNER TENANT IS VACATING PREMISES AND SERVICE HAS BEEN CONNECTED IN PROPERTY OWNER'S NAME PER AN AGREEMENT

2091(10-78)
(Rev. 12/80)

FOR YOUR INFORMATION

Your tenant, _____, has advised us that he is vacating the premises indicated below as of _____. In accordance with our agreement with you, we have connected the Electricity ☐ Gas ☐ service in your name.

_____ Account: _____

_____ Location: _____

_____ MONTANA-DAKOTA UTILITIES CO.

_____ By: _____

WHITE – District Office Copy

YELLOW – Customer Copy

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
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Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 13
Canceling Vol. 1 Original Sheet No. 16

GUARANTEE OF PAYMENT FOR NATURAL GAS AND/OR ELECTRIC SERVICE BY A SECOND PARTY IN LEIU OF A DEPOSIT

GUARANTEE OF PAYMENT FOR NATURAL GAS AND/OR
ELECTRIC SERVICE BY A SECOND PARTY IN LIEU OF A DEPOSIT

MONTANA-DAKOTA UTILITIES CO.
GUARANTEE OF PAYMENT FOR
NATURAL GAS AND/OR ELECTRIC SERVICE

(Date)

To: Montana-Dakota Utilities Co.

(Address)

(City, State, Zip Code)

For value received, I, _____ (Name of Guarantor), do hereby absolutely guarantee to pay to Montana-Dakota Utilities Co. (Montana-Dakota), upon its request and at the location listed above, the outstanding balance accrued by _____ (Name of Customer) in the event that Customer's bill for natural gas and/or electricity provided by Montana-Dakota at _____ (Customer's Service Address) is not paid when due; however, liability under this Guarantee, other than the collection costs noted below, shall not exceed the sum of $ _____. As Guarantor, I request copies of all disconnect notices sent to the Customer.

Liability under this Guarantee shall begin on _____, 19 ____, and shall continue until Customer has paid for natural gas and/or electric service when due in a prompt and satisfactory manner for twelve consecutive months in accordance with Public Service Commission or Public Utilities Commission rules. I expressly waive receipt of notice of Montana-Dakota's acceptance of my guarantee.

I also agree to pay any and all costs that Montana-Dakota may incur in the collection of this guarantee. In the event legal action is required or becomes necessary to collect the outstanding balance accrued by the Customer from me under this guarantee, I agree to pay all legal fees, including attorneys' fees, in the amount the court determines is reasonable.

I ACKNOWLEDGE THAT I HAVE CAREFULLY READ THE ABOVE GUARANTEE AGREEMENT AND THAT I HAVE RECEIVED A COPY OF IT.

GUARANTOR

_____ (Signature of Witness)

_____ (Signature of Guarantor)

_____ (Guarantor's Mailing Address)

_____ (Guarantor's Street Address—If Different than Mailing Address)

_____ (City, State, Zip Code)

_____ (Guarantor's Telephone Number)

DIVISION OFFICE – White Copy CUSTOMER COPY – Yellow Copy GUARANTOR COPY – Pink Copy

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 14
Canceling Vol. 1 1st Rev. Sheet No. 17

DEPOSIT WARNING LETTER

DEPOSIT WARNING LETTER

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

_____
Address Tel.

Date: _____

RE: Account _____

_____
(Service Address)

Dear _____:

This is to advise you that in the future should your utility service not be paid by the due date shown on your bill, Montana-Dakota Utilities Co. will require you to pay a deposit of $ _____.

Please keep your service bill current and avoid having to make this deposit.

Thank you.

Sincerely,

_____
(MDU Representative)

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 15
Canceling Vol. 1 Original Sheet No. 18

DEPOSIT REQUEST

DEPOSIT REQUEST

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

_____
Address Tel.

DEPOSIT REQUEST

Date: _____

RE: Account _____

_____
(Service Address)

Dear _____:

Previously you were advised that should your utility service not be paid by the due date shown on your bill, a deposit would be required.

Your payment history has not been satisfactory. This makes it necessary for us to request a deposit of $ _____ or an additional deposit of $ _____ to assure payment of your future bills. The deposit plus interest of _____ percent per year will be refunded to you after you have paid your monthly bills promptly for twelve months. If the deposit requested above is not paid on or before _____, action to discontinue service will be taken.

Name: _____

Mailing Address: _____

_____

_____

_____

Sincerely,

_____
(MDU Representative)

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
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Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 16

FINAL NOTICE PRIOR TO DISCONNECT

FINAL NOTICE PRIOR TO DISCONNECTION

OUR MDU REPRESENTATIVE WAS HERE at: _____ ❑ a.m. / ❑ p.m.
on _____ at the address of: _____
_____ and found no one at home.

YOUR SERVICE ACCOUNT IS SERIOUSLY PAST DUE!

CONSIDER THIS YOUR FINAL NOTICE AND THAT YOUR GAS AND/OR ELECTRIC SERVICE WILL BE:

DISCONNECTED ON: _____
UNLESS PAYMENT OF: $_____ IS PRESENTED TO THE CREDIT DEPARTMENT OF MONTANA-DAKOTA UTILITIES CO.
AT: _____
BY 5:00 P.M. ON _____

20124(3-80) (Rev. 4/00)

INTERRUPTIBLE GENERAL GAS SERVICE AGREEMENT

THIS AGREEMENT, made this [redacted] day of [redacted], 20[redacted], is by and between MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., a Delaware corporation, hereinafter called "Company", and [redacted], hereinafter called "Customer".

Customer and Company enter into this Interruptible General Gas Service Agreement to have natural gas delivered by Company to Customer.

WITNESSETH: The parties hereto, each in consideration of the agreement of the other, agree as follows:

1.0 TERM. Deliveries and charges hereunder shall commence as specified in Exhibit "A" attached hereto and incorporated herein. Customer agrees to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or Customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term.

2.0 DELIVERY POINT(S), RATE SCHEDULE(S), AND QUANTITIES. Delivery of natural gas under Small Interruptible General Gas Service Rate 71, or Large Interruptible General Gas Service Rate 85 by Company to Customer shall be as specified in attached Exhibit "A".

2.1 DISPATCHING. Customer will adhere to gas dispatching policies and procedures established by Company to facilitate service under this Agreement. Company will inform Customer of any changes in dispatching policies that may affect this Agreement as they occur.

2.2 METERING AND MEASUREMENT. Company will meter the quantity of natural gas delivered to Customer at the delivery point. Such quantities will be conclusive upon both parties unless such meter is found to be inaccurate by more than two percent, in which case the quantity delivered to Customer shall be determined by calculation, taking into consideration the time of year, the schedule of Customer's operations and other pertinent facts. Company will test the measurement equipment in accordance with applicable state utility commission rules and regulations.

3.0 DEFINITIONS.

Delivery Point - The point at which Customer assumes custody of the gas being delivered. This point will normally be at the outlet of Company's meter(s) located on Customer's premises.

Gas Day - Means a period of twenty-four consecutive hours, beginning and ending at 9:00 a.m. Central Clock Time.

Interruption - A suspension of interruptible natural gas service deemed necessary by Company pursuant to Rates 71 or 85 and 100.

4.0 RATE. The rates charged and services rendered Customer, under this agreement, shall be as specified in applicable Company tariffs as approved by the appropriate state utility commission.

The currently effective rate under this Agreement is subject to an adjustment for cost of purchased gas as provided in Purchased Gas Cost Adjustment Rate 88. Company shall have the right to modify the rates charged and the terms and conditions hereunder by making unilateral rate filings with the appropriate state utility commission.

4.1 TAXES. In addition to the rates specified above, Company shall collect from Customer and Customer agrees to pay Company any sales, use, excise, or other such taxes and city fees that are legally effective and applicable to the service provided hereunder.

4.2 INTERRUPTIBLE SALES GAS SERVICE. Service under Rate 71 and Rate 85 is dependent upon the availability of capacity on Company's system and prior demands of customers served under Company's general service gas rates. Customer agrees to accept service hereunder in accordance with Company's "Rate Schedule" as specified in Exhibit "A" of this Agreement.

4.3 CHANGE IN DAILY OPERATIONS. Customer agrees to notify Company of changes in Customer's natural gas requirements as specified in attached Exhibit "A". Company shall not be obligated to provide daily and annual requirements in excess of the daily and annual quantities set forth in Exhibit "A" unless Company, in its sole discretion, determines that increased quantities are available, and all quantities hereunder shall be subject to interruption and service priorities as provided in Rate 71 and Rate 85.

4.4 FIRM NATURAL GAS REQUIREMENTS. Customer agrees to accept service hereunder in accordance with Company's Rate 70, as specified in Exhibit "B" of this Agreement for Customer's firm requirements delivered through Customer's interruptible meter(s).

5.0 ASSIGNMENT. Customer agrees that it will not assign this Agreement except upon written consent of Company.

6.0 INDEMNIFICATION. Customer agrees to indemnify and hold Company harmless from any and all injury, loss or damage resulting from Customer's negligent or wrongful acts under and during the term of this Agreement. Company agrees to indemnify and hold Customer harmless from any and all injury, loss or damage resulting from Company's negligent or wrongful acts under and during the term of this Agreement.

7.0 INGRESS AND EGRESS. Company is hereby granted rights of ingress and egress, at reasonable times, for operating, inspecting and maintaining any of Company's facilities on Customer's premises.

8.0 FORCE MAJEURE. In the event of either Party's being rendered wholly or in part by force majeure unable to carry out its obligations under this Agreement, then the obligations of the Parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance of this Agreement by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance of this Agreement relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of Customer's gas are destroyed while in Company's posses-

sion by an event of force majeure, the obligations of the Parties under this Agreement shall terminate with respect to the volumes lost. The term "force majeure" as employed herein shall include, but shall not be limited to acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either Customer or Company under this Agreement, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of Company's gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the Party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the Party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this Agreement, when any such inability directly or indirectly contributes to or results in either Party's inability to perform its obligations.

9.0 REGULATORY AUTHORITY. This Agreement is subject to all valid laws, orders, rules and regulations of any and all duly constituted authorities having jurisdiction over the subject matter herein and is subject to the receipt of any necessary authorization for the interruptible service contemplated herein.

10.0 REPORTING REQUIREMENTS. Customer shall furnish Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date and year above written.

CUSTOMER	COMPANY
	MONTANA-DAKOTA UTILITIES CO., A Division of MDU Resources Group Inc.
By:	By: WILLIAM J. HUETHER Director of Marketing & Customer Services
Title:	
Witness*	
Title:	

* Please type or print the names below the signature lines.

INTERRUPTIBLE GENERAL GAS SERVICE AGREEMENT

This document is an attachment to the Interruptible General Gas Service Agreement dated [redacted] between Montana-Dakota Utilities Co. and [redacted] covering interruptible natural gas service to its facility located at [redacted]. Deliveries and charges hereunder shall commence on [redacted] and expire on [redacted].

Delivery Point	Rate Schedule	Rate*	Maximum Interruptible Delivery Point Quantity Per Day (dk)	Maximum Interruptible Delivery Point Annual Quantity (dk)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Customer agrees to notify Company of changes in its daily natural gas requirements in accordance with the following requirements:

Customer must inform company of the date the Customer's facility will start consuming natural gas as well as the date the Customer ceases consuming natural gas. The Company must receive this information by 10:00 a.m. Central Clock Time the day prior to either issue listed above.

Accepted and agreed to this [redacted] day of [redacted], 20[redacted].

By: [redacted]
Representing [redacted]

Accepted and agreed to this [redacted] day of [redacted], 20[redacted].

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

By: [redacted]
WILLIAM J. HUETHER
Director of Marketing &
Customer Services

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 18
Canceling Vol. 1 Original Sheet No. 23

REQUEST FOR FIRM NATURAL GAS SALES SERVICE

REQUEST FOR FIRM NATURAL GAS SALES SERVICE

This document is an attachment to the Interruptible General Gas Service Agreement dated [redacted] between Montana-Dakota Utilities Co. and [redacted] covering natural gas service to its facility located at [redacted].

Daily Firm Service Requirements

January	[redacted]	Dk/day
February	[redacted]	Dk/day
March	[redacted]	Dk/day
April	[redacted]	Dk/day
May	[redacted]	Dk/day
June	[redacted]	Dk/day
July	[redacted]	Dk/day
August	[redacted]	Dk/day
September	[redacted]	Dk/day
October	[redacted]	Dk/day
November	[redacted]	Dk/day
December	[redacted]	Dk/day

I hereby request that these daily maximum quantities be provided to this location pursuant to an approved firm natural gas sales tariff.

Firm gas sales, under Rate 70, shall commence on [redacted] and expire on [redacted], and shall continue thereafter until either party furnishes the other party 30 days written notice of termination.

[redacted]

By: [redacted]

By: [redacted]
(Please print or type)

Agreed to and accepted by Montana-Dakota Utilities Co. this [redacted] day of [redacted], 20[redacted].

By: [redacted]
(Gas Supply Department)

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

GAS TRANSPORTATION AGREEMENT

THIS AGREEMENT, made this _____ day of _____, 20____, is by and between MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., a Delaware corporation, hereinafter called "Company", and _____, located at _____ hereinafter called "Customer".

Customer has entered into agreements to purchase natural gas and have that gas delivered to a "receipt point" using Shipper(s) as specified in attached Exhibit "A" as Shipper. Customer agrees to notify Company prior to any change in shipper(s) and further agrees to execute a new Exhibit "A" prior to change of event.

Customer and Company enter into this Gas Transportation Agreement to have said gas transported by Company from the "receipt point" to a "delivery point".

WITNESSETH: The parties hereto, each in consideration of the agreement of the other, agree as follows:

1.0 TERM. Transportation, deliveries and charges hereunder shall commence on _____ and expire on _____, and shall continue thereafter until either party furnishes the other party 30 days written notice of termination.

2.0 RECEIPT POINT(S), DELIVERY POINT(S), RATE SCHEDULE(S), AND QUANTITIES. Delivery of natural gas under Firm General Gas Transportation Service Rate 84, Interruptible General Gas Transportation Service Rate 81, or Interruptible Industrial Gas Transportation Service Rate 82, by Company to Customer shall be at or near the points whose locations and maximum delivery quantity per day are described as follows. In the event said "Term of Rate", as specified in attached "Exhibit B", is not executed by both parties to this agreement, Customer agrees to pay Company the currently approved ceiling rate as specified under "Rate Schedule" below. Said "Term of Rate" shall not be executed for periods of less than 30 days.

Receipt Point	Delivery Points	Rate Schedule	Dk Maximum Delivery Point Quantity Per Day
_____	_____	_____	_____
Border Station	_____		
_____	_____		

2.1 DISPATCHING - Customer will adhere to gas dispatching policies and procedures established by Company to facilitate service under this Agreement. Company will inform Customer of any changes in dispatching policies that may affect this Agreement as they occur.

2.2 METERING AND MEASUREMENT - Company will meter the quantity of natural gas delivered to Customer at the delivery point. Company will test meter in accordance with applicable state utility rules and regulations. In addition, the parties agree to the following testing and corrective procedures:

2.2.1 CUSTOMER'S METER - Customer may install, operate and maintain at its sole expense, equipment for the purpose of measuring the amount of natural gas delivered over any measurement period (Customer meter), provided the equipment shall not interfere with such delivery or with the Company's meter.

2.2.2 ALTERNATIVE MEANS OF MEASUREMENT - In the event the Company's meter is out of service, measurement shall be determined by the following step process beginning with step "a" below:

a. Using the registration of the Customer's meter, if installed and accurately registering within two percent (2%) (either high of low); or
b. In the absence of accurate Customer metering, by making a calibration test or mathematical calculation, if the percentage of error is ascertainable; or
c. To the extent Customer's meter calibration test, or mathematical calculation described above cannot be utilized, by estimating by reference to quantities measured during periods under similar conditions when the Company's meter was registering accurately; or
d. To the extent the methods described above cannot be utilized, by estimating by reference to Customer's operating records for the period in question.

2.2.3 TESTING - The accuracy of the Company's electronic measurement device and the integrity of the meter shall be tested and calibrated in the presence of the Customer at a minimum of once each year. In addition, flow testing and calibration of the meter shall be performed in compliance with established Company policy for large meters at a minimum of once each five years. Company shall forward a copy of calibration documentation to Customer. In the event that either party notifies the other that it desires a test of the accuracy of its own or of the other party's meter, the parties shall cooperate to secure a prompt verification of the accuracy of such equipment. Notice shall be addressed to Company's Gas Superintendent at Company's _____ Office and shall be in writing at least fourteen days in advance of said testing.

2.2.4 COSTS OF TESTING - Company shall bear the cost of the testing and any required adjustment of the Company's meter. In the event that Customer requests a testing of Company's meter at other than the specified intervals, Customer shall bear the cost of the testing unless such equipment is found to be inaccurate by greater than two percent (2%) (either high or low).

2.2.5 CORRECTIONS OF MEASURING EQUIPMENT - If, upon testing, the Company's meter is found to be accurate within two percent (2%) (either high or low) at a flow rate corresponding to the average hourly flow rate for natural gas supplied by Company to Customer for the period since the last preceding test, previous recordings of such equipment shall be considered accurate in computing deliveries of natural gas hereunder, but Company meter shall be promptly adjusted to record correctly to the extent possible. If, upon testing, Company's meter shall be found to be inaccurate by greater than two percent (2%) (either high or low) at a flow rate corresponding to the average hourly flow rate for natural gas supplied by company to Customer for the period since the last preceding test, then such Company meter shall be promptly adjusted to record properly, to the extent possible, and any previous recordings by such Company meter shall be corrected to zero error, to the extent possible, and Company shall promptly send to Customer a report based on such corrected recordings and a revised invoice based on corrected readings within thirty days. If no reliable information exists as to when the Company meter became inaccurate, it shall be assumed for correction purposes hereunder that such inaccuracy began at a point in time midway between the testing date and the last previous date on which the Company meter was tested and found to be accurate or adjusted to be accurate.

2.2.6 MAINTENANCE - Each party shall have the right to be present whenever the other party reads, cleans, changes, repairs, inspects, tests, calibrates, or adjusts its meter. Each party shall give timely notice to the other party in advance of taking any such actions. Notice shall be addressed to Company's Gas Superintendent at Company's _____ Office. Each party shall give at least 24 hours notice to the other party prior to undertaking the above-described activity.

2.2.7 CHARGES, PENALTIES, COSTS, OR EXPENSES - To the extent that any penalties are incurred by Customer as a result of the inaccuracy of Company's meter greater than two percent (2%) (either high or low), Company shall be responsible for such penalties.

2.2.8 ELECTRONIC MEASUREMENT EQUIPMENT - The Company's electronic (Metretek) measurement, used as a remote terminal unit for system operations, equipment is excluded from the requirements of Sections 2.2.2, 2.2.3, 2.2.4, 2.2.5, 2.2.6, and 2.2.7. The estimated cost of the installation of electronic measurement equipment in conjunction with this Agreement is $_____. Customer agrees to provide this amount to Company at the time this Agreement is returned to Company for execution by Company.

2.2.9 RECORD EXAMINATION - Customer shall have the right at all reasonable times to examine the books, records and charts of Company, for a two year period subsequent to the issuance in writing of a dispute invoice, to the extent necessary to verify the accuracy of any statement, charge or computation made under or pursuant to any provisions of this agreement.

3.0 DEFINITIONS.

Delivery Point - The point at which Customer assumes custody of the gas being transported. This point will normally be at the outlet of Company's meter(s) located on Customer's premises.

Gas Day - Means a period of twenty-four consecutive hours, beginning and ending at 9:00 a.m. Central Clock Time.

Interruption - A suspension of transportation or retail natural gas service deemed necessary by Company.

Nomination - The daily volume, in dk, of natural gas requested by Customer for transportation and delivery to Customer at the delivery point over a 24 hour period commencing at 9:00 a.m. Central Clock Time each day.

Receipt Point - The intertie between Company and the interconnecting pipeline(s) at which point Company assumes custody of the gas being transported.

Shipper - The party with whom the pipeline has entered into a Service Agreement for transportation service.

4.0 RATE. The rates charged Customer shall be as specified in applicable Company tariffs as approved by the appropriate state utility regulatory agency.

The currently effective rates are attached hereto and made a part hereof. Company shall have the right to modify the rates charged and the terms and conditions hereunder by making unilateral rate filings with the appropriate regulatory agency.

4.1 FIRM NATURAL GAS REQUIREMENTS. Customer agrees to accept service hereunder in accordance with Company's Rate 70, as specified in Exhibit "C" of this Agreement

for Customer's firm requirements delivered through Customer's interruptible meter(s).

4.2 TAXES. In addition to the rates specified above, Company shall collect from Customer and Customer agrees to pay Company any sales, use, excise, or other such taxes and city fees that are legally effective and applicable to the service provided hereunder.

4.3 REPLACEMENT OR SUPPLEMENTAL SALES SERVICE. Interruptible retail gas may be available at this location during the time that this Agreement is in force. Customer may request that Company provide interruptible retail gas sales pursuant to Rate Schedule _____. Service under such rate is subject to the availability of capacity on Company's system and prior demands of customers served under Company's general service gas rates.

5.0 ASSIGNMENT. Customer agrees that it will not assign this Agreement except upon written consent of Company.

6.0 INDEMNIFICATION. Customer agrees to indemnify and hold Company harmless from any and all injury, loss or damage resulting from Customer's negligent or wrongful acts under and during the term of this Agreement. Company agrees to indemnify and hold Customer harmless from any and all injury, loss or damage resulting from Company's negligent or wrongful acts under and during the term of this Agreement.

7.0 INGRESS AND EGRESS. Company is hereby granted rights of ingress and egress, at reasonable times, for operating, inspecting and maintaining any of Company's facilities on Customer's premises.

8.0 FORCE MAJEURE. In the event of either Party's being rendered wholly or in part by force majeure unable to carry out its obligations under this Agreement, then the obligations of the Parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance of this Agreement by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance of this Agreement relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of Customer's gas are destroyed while in Company's possession by an event of force majeure, the obligations of the Parties under this Agreement shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either Customer or Company under this Agreement, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of Company's gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the Party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the Party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this Agreement, when any such inability directly or indirectly contributes to or results in either Party's inability to perform its obligations.

9.0 REGULATORY AUTHORITY. This Agreement is subject to all valid laws, orders, rules and regulations of any and all duly constituted authorities having jurisdiction over the subject matter herein and is subject to the receipt of any necessary authorization for the transportation service contemplated herein.

10.0 REPORTING REQUIREMENTS. Customer shall furnish Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date and year above written.

CUSTOMER	COMPANY
	MONTANA-DAKOTA UTILITIES CO., A Division of MDU Resources Group Inc.
By: *	By: William J. Huether Director of Marketing & Customer Services
Title:	
Attest: *	
Title:	

* Please type or print the names below the signature lines.

EXHIBIT "A"
GAS TRANSPORTATION AGREEMENT

This document is an attachment to the Gas Transportation Agreement dated [redacted] between Montana-Dakota Utilities Co. and [redacted] covering natural gas transportation service to Customer's facility located at [redacted].

This Exhibit "A" shall be in effect commencing on [redacted].

Customer's Total Interruptible Transportation Quantity: [redacted] dk per day.

Customer's Total Firm Transportation Quantity: [redacted] dk per day.

The shipper(s) name is [redacted]

Customer hereby authorizes Company to furnish the shipper any information relating to the volume and/or cost of natural gas furnished by Company for use by Customer. This authorization will remain in effect until a written notice is received from Customer.

Accepted and agreed to this [redacted] day of [redacted], 20[redacted].

CUSTOMER

[redacted]

By: [redacted]

Representing [redacted]

Accepted and agreed to this [redacted] day of [redacted], 20[redacted].

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

By: [redacted]
William J. Huether
Director of Marketing & Customer Services

EXHIBIT "B"
GAS TRANSPORTATION AGREEMENT

This document is an attachment to the Gas Transportation Agreement dated _____ between MONTANA-DAKOTA UTILITIES CO. and _____ covering natural gas transportation service to Customer's facility located at _____.

Rate	Term of Rate
_____	_____

Accepted and agreed to this ____ day of _____, 20____.

_____

By: _____

Title: _____

Accepted and agreed to this ____ day of _____, 20____.

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

By: _____
William J. Huether
Director of Marketing & Customer Services

GAS TRANSPORTATION AGREEMENT

EXHIBIT "C"
REQUEST FOR FIRM NATURAL GAS SALES SERVICE

This document is an attachment to the Gas Transportation Agreement dated _____ between Montana-Dakota Utilities Co. and _____ covering natural gas transportation service to Customer's facility located at _____.

Daily Firm Service Requirements

January	_____	Dk/day
February	_____	Dk/day
March	_____	Dk/day
April	_____	Dk/day
May	_____	Dk/day
June	_____	Dk/day
July	_____	Dk/day
August	_____	Dk/day
September	_____	Dk/day
October	_____	Dk/day
November	_____	Dk/day
December	_____	Dk/day

I hereby request that these daily maximum quantities be provided to this location pursuant to an approved firm natural gas sales tariff.

Firm gas sales, under Rate 70, shall commence on _____ and expire on _____, and shall continue thereafter until either party furnishes the other party 30 days written notice of termination.

_____

By: _____

By: _____
(Please print or type)

Agreed to and accepted by Montana-Dakota Utilities Co. this ____ day of _____, 20____.

_____
(Gas Supply Department)

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 20
Canceling Vol. 1 1st Rev. Sheet No. 26

CUSTOMERS AGREEMENT FOR GAS EXTENSION

[Rev. 11/99]

INTERRUPTIBLE GAS SERVICE
EXTENSION AGREEMENT (RATE 119)

THIS AGREEMENT, made and entered into this _____ day of _____, _____, by and between MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., a Delaware Corporation, 400 North Fourth Street, Bismarck, North Dakota, hereinafter called "Company," and _____ hereinafter called "Customer," whether one or more.

WHEREAS, Customer has requested that Company provide natural gas service to Customer at the following location:

County of _____, State of _____; and

WHEREAS, such service will necessitate the construction by Company of a gas main extension, and the installation of the necessary facilities.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, it is hereby agreed as follows:

1. Company agrees to construct and install said natural gas Project in accordance with the Interruptible Gas Service Extension Policy Rate 119, attached hereto and incorporated herein, and Customer agrees that, prior to construction of same, Customer will pay to Company the required cost participation for the Project, in the sum of $ _____, to be paid as follows:

2. It is further agreed that after facilities have been placed in service, Company shall recalculate the Customer's cost participation as outlined below:

Final Actual Cost of Project	$_____
Adjusted for Federal and State Income Taxes	$_____
Preliminary Cost Participation	$ 0.00
Difference to be: ☐ Paid to Company	$_____
☐ Refunded to Customer	$_____

3. Interest will be paid by Company to Customer on any refunds made to Customer who has made a cash contribution for the Project. On any refund amounts, interest will be calculated annually by the Company at the rate required pursuant to the Interruptible Gas Service Extension Policy Rate 119 applicable in the state in which the Project is located.
4. "Project", as used in this Agreement, shall include the gas main extension(s), valves, service stub(s), or service line(s) complete where applicable, regulators, meters (excluding electronic measurement equipment), any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs as adjusted for applicable federal and state income taxes.
5. This Agreement applies only to Company-owned facilities and does not apply to Customer-owned gas service lines. Company shall not be liable for any damages on account of injury to or death of persons, or damage to property, due to the operation, maintenance, repair or replacement of the Customer's service line or customer-owned piping and equipment. All duties and liabilities in this respect are assumed by the Customer.
6. The following additional terms and conditions shall apply to Company's construction of a gas main and installation of the necessary facilities as follows:

7. The following listed documents are attached hereto, and incorporated herein as part of the Agreement:
   a. Interruptible Gas Service Extension Policy, effective date:
   b. Estimate of Construction Costs
   c. Map showing the route of the extension
   d. Economic Analysis of the extension
8. This Agreement shall be binding upon and inure to the benefit of the parties, their respective successors and assigns; but the assignment of this Agreement by either party shall not relieve such party, without the written consent of the other, from any of the obligations undertaken by this Agreement. Further, this Agreement shall expire on December 1, of the year in which it was signed by the Company, or on the following date, _____, whichever is later, if construction of the extension has not begun. If the Agreement expires, Company will refund any deposit made by Customer and, thereafter, all parties shall be relieved from any and all further liability in connection with this Agreement.
   a. If, within the five-year period after the extension(s) in service date, the total of customer's contribution and actual margin to the Company equals or exceeds the total present value of the revenue requirement associated with the extension, the Company shall refund the amount exceeding the revenue requirement, in accordance with the Interruptible Gas Service Extension Policy Rate 119.
   b. No refund shall be made by Company to Customer after the five-year refund period has expired, and in no case shall the refund, excluding interest, exceed the amount of contribution made by the Customer.

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

Customer	Date	Region Manager	Date

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

21447(12-91)
(Rpv. 11/00)

FIRM GAS SERVICE
EXTENSION AGREEMENT (RATE 120)

THIS AGREEMENT, made and entered into this _____ day of _____, _____, by and between MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., a Delaware Corporation, 400 North Fourth Street, Bismarck, North Dakota, hereinafter called "Company," and _____ hereinafter called "Customer," whether one or more.

WHEREAS, Customer has requested that Company provide natural gas service to Customer at the following location:

County of _____, State of _____, and

WHEREAS, such service will necessitate the construction by Company of a gas main extension and the installation of the necessary facilities.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, it is hereby agreed as follows:

1. Company agrees to construct and install said natural gas Project in accordance with the Firm Gas Service Extension Policy Rate 120 and Customer agrees that, prior to construction of same, Customer will pay to Company the required cost participation for the Project, in the sum of $ _____, to be paid as follows:

2. It is further agreed that after facilities have been placed in service, Company shall recalculate the Customer's cost participation as outlined below.

Final Actual Cost of Project	$ _____
Less Maximum Allowable Investment (per Rate 120)	$ _____
Final Cost Participation	$ _____
Preliminary Cost Participation	$ 0.00
Difference to be: ☐ Paid to Company	$ _____
☐ Refunded to Customer	$ _____

3. Interest will be paid by Company to Customer on any refunds made to Customer who has made a cash contribution for the Project. On any refund amounts, interest will be calculated annually by the Company at the rate required pursuant to the Firm Gas Service Extension Policy Rate 120 applicable in the state in which the project is located.

4. "Project", as used in this Agreement, shall include the gas main extension(s), valves, service stub(s), or service line(s) complete where applicable, any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs excluding the distribution meter and regulator.

5. This Agreement applies only to Company-owned facilities and does not apply to Customer-owned gas service lines. Company shall not be liable for any damages on account of injury to or death of persons, or damage to property, due to the operation, maintenance, repair or replacement of the Customer's service line or customer-owned piping and equipment. All duties and liabilities in this respect are assumed by the Customer.

6. The following additional terms and conditions shall apply to Company's construction of a gas main and installation of the necessary facilities as follows:

7. The following documents are attached hereto, and incorporated herein, as part of the Agreement:
   a. Estimate of construction costs
   b. Map showing the route of the extension
   c. Economic analysis of the extension
   d. Firm Gas Service Extension Policy, effective date:

8. This Agreement shall be binding upon and inure to the benefit of the parties, their respective successors and assigns; but the assignment of this Agreement by either party shall not relieve such party, without the written consent of the other, from any of the obligations undertaken by this Agreement. Further, this Agreement shall expire on December 1, of the year in which it was signed by the Company, or on the following date, _____, whichever is later, if construction of the extension has not begun. If the Agreement expires, Company will refund any deposit made by Customer and, thereafter, all parties shall be relieved from any and all further liability in connection with this Agreement.
   a. If, within the five-year period after the extension(s) in service date, the number of active customers and related volumes exceeds the projections used in the economic analysis, the Company shall recompute the participation requirement by recalculating the maximum allowable investment, in accordance with the Firm Gas Service Extension Policy Rate 120. No refund shall be made by Company to Customer until the new applicants begin taking service from the Company.
   b. If after the aforementioned five-year period, the Customer's participation amount of $ _____ has not been fully refunded by that time, the obligation of the Company to make refunds shall cease. In no event, shall the total amount of refunds exceed the amount paid to Company hereunder.

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

_____	_____	_____	_____
Customer	Date	Region Manager	Date

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 21
Canceling Vol. 1 Sub. Original Sheet No. 28

GAS SERVICE ORDER

GAS SERVICE ORDER (Form 29927 Rev. 1-01) FARM TAP ACCOUNT: ___YES ___NO

REGION | SERVICE ADDRESS

EFV: ___YES ___NO | TOWN | STATE | ___ADDITION ___RETIREMENT

TOWNSHIP/RANGE | SECTION | BLOCK | LOT | CITY LIMITS: ___INSIDE ___OUTSIDE

MAP NO. | SUBDIVISION | LOCATE NO.

SERVICE ORDER EXPIRATION DATE:_____

Customer Name:_____

Mailing Address:_____

Telephone Number: Home:_____

Work:_____ Cell:_____

	ACCT. NO.	ESTIMATE / IMO
____ Excess Flow Valve: ___.5" ___.75" ___1"		$_____
____ New Service Line, Price Per Foot	(.28796)	$_____
____ New Service Line,Time & Material	(.28796)	$_____
____ Replacement Service Line, Price Per Foot	(.28797)	$_____
____ Replacement Service Line, Time & Material	(.28797)	$_____
____ Relocate or Repair Portion of SL	(.28799)	$_____
____ Installation of Customer Owned Line (8360) (May require signed merchandise order)		
____ Related charges		$_____

☐ Residential ☐ New Construction ☐ Billing in Full
☐ Mobile Home ☐ Conversion ☐ 12 Payments
☐ Commercial ☐ Replacement Other:_____

ESTIMATED GAS INPUT:_____CFH

IT IS THE CUSTOMER'S RESPONSIBILITY TO LOCATE AND MARK PRIVATE UNDERGROUND FACILITIES ON THIS PROPERTY. THE CUSTOMER SHALL BE RESPONSIBLE FOR DAMAGES TO UNMARKED FACILITIES OR FOR CHANGES RESULTING FROM IMPROPER METER LOCATION OR GRADE LEVEL. PRICES PERTAIN TO NORMAL DIGGING AND BACKFILLING CONDITIONS. ADDITIONAL CHARGES WILL BE LEVIED FOR: 1)Excavating in frozen or rocky ground, 2)concrete/asphalt removal and/or replacement, 3)tamping to meet compaction specifications, and 4) hand digging/backfilling to meet landscaping specifications.

I RECEIVED INFORMATION CONCERNING EXCESS FLOW VALVES AND ___REQUEST/DECLINE___ (CHECK THE APPROPRIATE RESPONSE) TO HAVE AN EXCESS FLOW VALVE INSTALLED ON THE SERVICE LINE I REQUESTED. I agree to all conditions of this order.

CUSTOMER SIGNATURE DATE

ORDER RECEIVED BY DATE

CUSTOMER ACCOUNT NO.:_____

STUB WORK ORDER NO._____ DOC NO._____

SERVICE LINE WORK ORDER NO.:_____ DOC NO._____

GAS MAIN EXTENSION WORK ORDER NO._____ DOC NO._____

CREDIT APPROVAL:_____ MAIN EXTENSION REQUIRED? ___YES ___NO

CONTRIBUTION MAIN? ___YES ___NO CONTRIBUTION RECEIVED? ___YES ___NO

SPECIAL INSTRUCTIONS:_____

TOTAL COSTS_____

LABOR $_____ MATERIALS $_____ EQUIPMENT $_____

JOB START DATE:_____ JOB COMPLETION DATE:_____

HOURS _____ GAS MAIN WORK (.2887___) BILLABLE: ___YES ___NO

HOURS _____ GAS STUB WORK (.2892___) BILLABLE: ___YES ___NO

WORKED PERFORMED:_____

ENGINEERING DATA:

ASPHALT/CONCRETE: ___YES ___NO

CURB BOX: ___YES ___NO

METER GUARD: ___YES ___NO

REG./ORIFICE SIZE:_____

METER SIZE:_____

RISER SIZE:_____

IS RISER CATHODICALLY PROTECTED? ___YES ___NO

JOINT TRENCH:

TELEPHONE_____ POWER_____

CABLE TV_____ REC_____

RISER LOCATION:_____

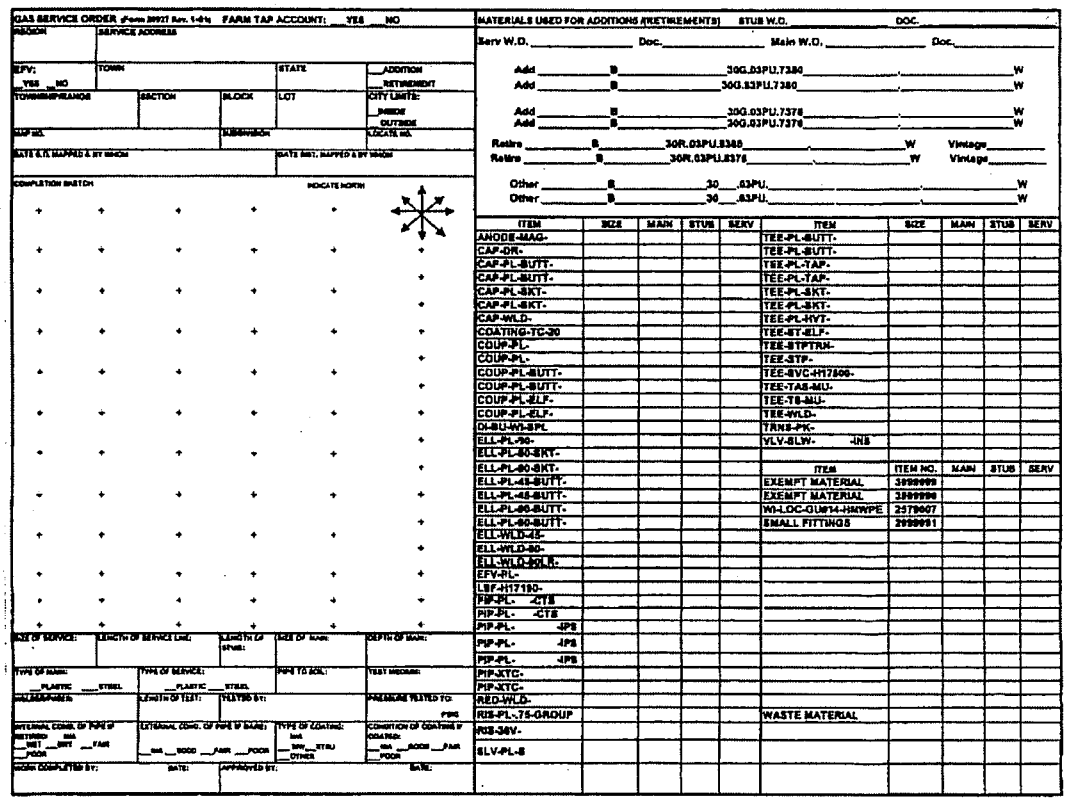
Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 21.1

GAS SERVICE ORDER



GAS SERVICE ORDER FARM TAP ACCOUNT: YES NO

REGION | SERVICE ADDRESS

EFV: YES NO | TOWN | STATE | ADDITION / RETIREMENT

TOWNSHIP/RANGE | SECTION | BLOCK | LOT | CITY LIMITS: WITHIN / OUTSIDE

MAP NO. | SUBDIVISION | LOCATE NO.

DATE S.K. MAPPED & BY WHOM | DATE SKET. MAPPED & BY WHOM

COMPLETION SKETCH | INDICATE NORTH

SIZE OF SERVICE: | LENGTH OF SERVICE LINE: | LENGTH OF STUB: | SIZE OF MAIN: | DEPTH OF MAIN:

TYPE OF MAIN: PLASTIC STEEL | TYPE OF SERVICE: PLASTIC STEEL | PIPE TO SOIL: | TEST MEDIUM:

VALVE/CURB NO. | LENGTH OF TEST: | TEST PSI: | PRESSURE TESTED TO: PSIG

INTERNAL COND. OF PIPE IF RETIRED: N/A WET DRY FAIR POOR | EXTERNAL COND. OF PIPE IF BARE: N/A GOOD FAIR POOR | TYPE OF COATING: N/A TAPE MTU OTHER | CONDITION OF COATING IF COATED: N/A GOOD FAIR POOR

WORK COMPLETED BY: | DATE: | APPROVED BY: | DATE:

MATERIALS USED FOR ADDITIONS (RETIREMENTS) STUB W.O. DOC.

Serv W.O. Doc. Main W.O. Doc.

Add B 30G.03PU.7380 W
Add B 30G.03PU.7380 W

Add B 30G.03PU.7376 W
Add B 30G.03PU.7376 W

Retire B 30R.03PU.8385 W Vintage
Retire B 30R.03PU.8376 W Vintage

Other B 30 .03PU. W
Other B 30 .03PU. W

ITEM	SIZE	MAIN	STUB	SERV
ANODE-MAG-				
CAP-DR-				
CAP-PL-BUTT-				
CAP-PL-BUTT-				
CAP-PL-SKT-				
CAP-PL-SKT-				
CAP-WLD-				
COATING-TC-30				
COUP-PL-				
COUP-PL-				
COUP-PL-BUTT-				
COUP-PL-BUTT-				
COUP-PL-ELF-				
COUP-PL-ELF-				
DI-BU-WI-SPL				
ELL-PL-90-				
ELL-PL-90-SKT-				
ELL-PL-90-SKT-				
ELL-PL-45-BUTT-				
ELL-PL-45-BUTT-				
ELL-PL-90-BUTT-				
ELL-WLD-45-				
ELL-WLD-90-				
ELL-WLD-90LR-				
EFV-PL-				
LBF-H17190-				
PIP-PL- -CTS				
PIP-PL- -CTS				
PIP-PL- -IPS				
PIP-PL- -IPS				
PIP-PL- -IPS				
PIP-XTC-				
PIP-XTC-				
RED-WLD-				
RIS-PL-.75-GROUP				
RIS-36V-				
SLV-PL-S				

ITEM	SIZE	MAIN	STUB	SERV
TEE-PL-BUTT-				
TEE-PL-BUTT-				
TEE-PL-TAP-				
TEE-PL-TAP-				
TEE-PL-SKT-				
TEE-PL-SKT-				
TEE-PL-HYT-				
TEE-ST-ELF-				
TEE-STPTRN-				
TEE-STP-				
TEE-SVC-H17500-				
TEE-TAS-MU-				
TEE-TS-MU-				
TEE-WLD-				
TRNS-PK-				
YLV-SLW- -INS				

ITEM	ITEM NO.	MAIN	STUB	SERV
EXEMPT MATERIAL	3999999			
EXEMPT MATERIAL	3999998			
WI-LOC-GUM14-HWIPE	2579007			
SMALL FITTINGS	2999991			
WASTE MATERIAL				

Date Filed: December 30, 2002

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.: NG02-011

Effective Date: Service Rendered on and after December 2, 2003

Implemented
December 4, 2003

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

FACILITIES RELOCATION AGREEMENT

FACILITIES RELOCATION AGREEMENT

THIS AGREEMENT is entered into this _____ day of _____, 19____, by and between MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc. (hereinafter "Montana-Dakota"), and _____, whose address is _____ (hereinafter "Requestor").

WHEREAS, Requestor desires the relocation of (gas) (electric) facilities by Montana-Dakota and Montana-Dakota is willing to relocate the facilities in accordance with the terms and conditions of this Agreement;

NOW, THEREFORE, Montana-Dakota and Requestor agree as follows:

1. Requestor desires the relocation of (gas) (electric) facilities at the following address:
   _____
   _____
   _____
   Order/GSSO/ECO Number _____
   Date of Request: _____
   Requestor Billing Address: _____
   _____

2. The estimated cost of the desired relocation of facilities is _____. A deposit of _____ shall be made by Requestor with Montana-Dakota prior to relocation work commencing. Upon completion of the relocation work, Montana-Dakota shall determine the actual cost of relocation. If the actual cost of relocation exceeds the amount of deposit, Requestor shall pay Montana-Dakota the difference between the amount of deposit and the actual cost within 30 days from billing. If the amount of the deposit exceeds the actual cost of the relocation, Montana-Dakota shall refund the difference to Requestor within 30 days after job completion. If the relocation work has not commenced within 60 days from the above Agreement date, this Agreement shall expire and Requestor's deposit shall be refunded within 30 days thereafter.

3. This Agreement shall be binding upon the parties, their respective successors and assigns. The assignment of this Agreement by either party shall not relieve such party, without the written consent of the other, from any of the obligations undertaken by this Agreement.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date above written.

REQUESTOR	**MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc.**
By: _____	By: _____

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

WARNING NOTICE

WARNING NOTICE

NAME:_____

ADDRESS: _____

TOWN: _____ METER: _____

We have observed your _____
(Name of appliance)

and found an unsafe/unsatisfactory condition due to:

_____

_____

_____

_____

_____

_____

This condition can be corrected by:

_____

_____

_____

_____

_____

_____

IN THE INTEREST OF SAFETY AND GOOD SERVICE, YOU ARE URGED TO HAVE YOUR LOCAL CONTRACTOR OR MONTANA-DAKOTA UTILITIES CO. CORRECT THIS CONDITION AT ONCE.

After the repair or replacement is completed, please notify our customer service department at: 1-800-638-3278

- **UNSATISFACTORY CONDITION EQUIPMENT:**
  ☐ LEFT ON ☐ LEFT OFF
- **UNSAFE CONDITION EQUIPMENT:**
  ☐ SHUT OFF ☐ LEFT ON (Explain)

_____

_____

_____

NOTICE REC'D BY: _____
(Customer Signature)

☐ Owner ☐ Occupant ☐ Other _____

MDU By: _____

Date: _____

Certified Letter Sent (Date):_____

20241-G(4-73)
(Rev. 9/01)

MONTANA-DAKOTA UTILITIES CO.

Date Filed:	December 30, 2002	**Effective Date:**	Service Rendered on and after December 2, 2003
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		Implemented December 4, 2003
Docket No.:	NG02-011		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TEMPORARY CONSTRUCTION HEAT AGREEMENT

TEMPORARY CONSTRUCTION HEAT AGREEMENT

THIS AGREEMENT, entered into this _____ day of _____, 20 ___, by and between Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., 400 North Fourth Street, Bismarck, North Dakota, hereinafter referred to as "Company", and _____ of _____, hereinafter referred to as "Customer."

WHEREAS, Company is a public utility engaged in the sale of natural gas; and

WHEREAS, Customer has requested that Company provide natural gas service for temporary heating purposes during construction at the following-described property:

_____
_____
_____
_____

NOW, THEREFORE, In consideration of the mutual promises and convenants herein contained, it is mutually agreed as follows:

1. Company agrees to provide natural gas service to Customer at the above-described property on an interruptible/firm basis for temporary heating purposes. Customer agrees to pay Company for said service in accordance with Company's filed rates and agrees to pay Company for the installation of any temporary service lines, meters, regulators and/or other equipment, as well as for removal of the same upon termination of said service, the amount of such payment to be commensurate with the amount customarily charged by Company for such installation and/or removal.

2. Customer represents and warrants that all equipment used to supply temporary heat to the above-described property is approved by a nationally recognized testing agency or authority and is and will remain in good, workable and safe condition. Customer further represents and warrants that the said equipment is or will be installed in a good, workmanlike and safe manner so that same may be used without the creation of an unsafe or hazardous condition to persons or property. Customer further represents and warrants that the said equipment will meet the following standards:

   (a) All heating units designed for venting will be adequately and safely vented.
   (b) Adequate fresh air ventilation will be provided to approved unvented heating units so that operation of the units will not create an unsafe or hazardous working atmosphere.
   (c) Where heating units are connected with a flexible hose, the hose will be AGA or UL approved and have a working pressure at least 350 psi and be located so that it will not be damaged in any way by any construction or other activities. A shut-off valve will be installed at the inlet end of the hose.
   (d) Pressure regulators at equipment will be properly installed and vented.
   (e) Gas pressure will be limited to ten (10) psig in any piping inside the building.
   (f) Gas piping installations (including material and size), as well as all heating and auxiliary equipment, will comply with all code standards and requirements, as well as all Federal, State or local rules and regulations.
   (g) Flexible metal tubing such as corrugated stainless steel tubing (CSST) will not be used in temporary installations.
   (h) Flexible hose that will be operating between 14" WC (1/2 PSIG) up to and including 5 PSIG will be tested at a minimum pressure of 60 PSIG for a minimum of 30 minutes, and systems designed for over 5 PSIG up to and including 10 PSIG will be tested at 100 PSIG for a minimum of 30 minutes.

3. Customer agrees to indemnify and hold the Company harmless from and against any and all claims and liability for loss, injury, or damages to person or property arising directly or indirectly from the breach of any warranty or representation contained herein and/or from the installation or operation of any equipment connected to the Company's service lines.

4. This Agreement shall not be construed as granting to Customer a priority to gas, and it is agreed that Company shall not be liable to Customer for interruption or suspension of service.

IN WITNESS WHEREOF, the parties hereto have caused these presents to be executed as of the day and year first above written.

MONTANA-DAKOTA UTILITIES CO.

BY: _____

CUSTOMER: _____

BY: _____

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 1
1st Revised Sheet No. 1
Canceling Original Sheet No. 1

TABLE OF CONTENTS

Designation	Title	Sheet No.
Section No. 1	Table of Contents	1
Section No. 2	Preliminary Statement	1
Section No. 3	Rate Schedules	
	Rate Summary Sheet	1
Rate 60	Residential Gas Service	2
	Reserved for Future Use	3-4
Rate 64	Ellsworth Air Force Base	5
	Reserved for Future Use	6
Rate 66	East River Natural Gas System General Services	7
	Reserved for Future Use	8-10
Rate 70	Firm General Gas Service	11
Rate 71	Small Interruptible General Gas Service	12
Rate 72	Optional Seasonal General Gas Service	13
	Reserved for Future Use	14-21
Rate 81 and 82	Transportation Service	22
	Reserved for Future Use	23-25
Rate 85	Large Interruptible General Gas Service	26
	Reserved for Future Use	27
Rate 87	Distribution Delivery Stabilization Mechanism	28
Rate 88	Purchased Gas Cost Adjustment	29
Rate 89	East River Natural Gas System Purchase Gas Cost Adjustment	30
Section No. 4	List of Contracts with Deviations	1
Section No. 5	Rules	
Rate 100	General Provisions	1
	Reserved for Future Use	2
Rate 102	Residential Rate for Regular Employees	3
	Reserved for Future Use	4-18
Rate 119	Interruptible Gas Service Extension Policy	19
Rate 120	Firm Gas Service Extension Policy	20
	Reserved for Future Use	21-23

Date Filed: June 7, 2004 **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.: NG04-___

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TABLE OF CONTENTS

Rate 124	New Installation, Replacement, Relocation and Repair of Gas Service Lines	24
	Reserved for Future Use	25-33
Rate 134	Rules and Policies for Implementing Master Metering Restrictions	34
Section No. 6	Sample Forms	
	Consumer's Deposit Receipt	1
	New Customer Application Card	2
	Gas Meter Order	3
	Standard Customer Bill	4
	Disconnect Notice	5
	Application for Interruptible Natural Gas Service	6
	Customer Information Booklet	7
	Discontinuance Notices for Causes Other Than Nonpayment of Bills	8
	Third Party Notice	9
	Deferred Installment Agreement Form	10
	Agreement by Property Owner or Agent to Pay Utility Bills During Periods When Property is Unoccupied	11
	Reserved for Future Use	12
	Guarantee of Payment for Natural Gas and/or Electric Service by a Second Party in Lieu of a Deposit	13
	Deposit Warning Letter	14
	Deposit Request	15
	Final Notice Prior to Disconnect	16
	Interruptible General Gas Service Agreement	17
	Request for Firm Natural Gas Sales Service	18
	Gas Transportation Agreement	19
	Customers Agreement for Gas Extension	20
	Gas Service Order	21
	Facilities Relocation Agreement	22
	Warning Notice	23
	Temporary Construction Heat Agreement	24

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
1st Revised Sheet No. 2
Canceling Original Sheet No. 2

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served, except for those communities set forth on Rate 66, for all domestic uses. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	$0.26 per day
Distribution Delivery Charge:	$1.666 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

General Terms and Conditions:

RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
1st Revised Sheet No. 11
Canceling Original Sheet No. 11

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served, except for those communities set forth on Rate 66, for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:		
For customers with meters rated under 500 cubic feet per hour	$0.35 per day	I
For customers with meters rated over 500 cubic feet per hour	$0.70 per day	I
Distribution Delivery Charge:	$1.226 per dk	I
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
1st Revised Sheet No. 13
Canceling Original Sheet No. 13

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served, except for those communities set forth on Rate 66, for customers otherwise qualifying for service under Firm General Gas Service Rate 70. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.35 per day I
For customers with meters rated over 500 cubic feet per hour	$0.70 per day I
Distribution Delivery Charge:	$1.226 per dk I
Cost of Gas:	
Winter – Bills rendered October 1 through May 31	Determined Monthly – See Rate Summary Sheet for Current Rate
Summer – Bills rendered June 1 through September 30	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TRANSPORTATION SERVICE Rates 81 and 82

Rate:

Basic Service Charge:

Rate 81	$125.00 per month 1/
Rate 82	$225.00 per month 2/

1/ In the event customer takes service through one meter under both Rates 71 and 81, the base rate under Rate 81 shall be waived.

2/ In the event customer takes service through one meter under both Rates 85 and 82, the base rate under Rate 82 shall be waived.

Under Rates 81 or 82 customer shall pay a negotiated rate not more than the maximum rate or less than the minimum rate specified below. (The per dk charge is applicable to all dk of natural gas transported under the terms of this rate.)

	Rate 81	Rate 82
Maximum Rate per dk	$0.453	$0.183
Minimum Rate per dk	$0.131	$0.090
Balancing Charge per dk	$0.300	$0.300

Fuel Charge:

Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See Rate Summary Sheet for currently effective charge.

GENERAL TERMS AND CONDITIONS:

1. CRITERIA FOR SERVICE – In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. The customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
1st Revised Sheet No. 26
Canceling Original Sheet No. 26

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served, except those communities set forth on Rate 66, for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will exceed 40,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement. The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

This rate schedule shall not apply for service to U. S. Government installations, which are covered by separate special contracts.

Rate:

Basic Service Charge:	$175.00 per month	I
Distribution Delivery Charge:		
Maximum Rate	$0.183 per dk	I
Minimum Rate	$0.090 per dk	
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
1st Revised Sheet No. 1
Canceling Original Sheet No. 1

TABLE OF CONTENTS
GENERAL PROVISIONS Rate 100

Title		Page No.
I.	Purpose	3
II.	Definitions	3-5
III.	Customer Obligations	
	1. Application for Service	5
	2. Input Rating	5
	3. Access to Customer's Premises	6
	4. Company Property	6
	5. Interference with Company Property	6
	6. Relocated Lines	6
	7. Notification of Leaks	6
	8. Termination of Gas Service	6
	9. Reporting Requirement	6
	10. Quality of Gas	7
IV.	Liability	
	1. Continuity of Service	7
	2. Customer's Equipment	7
	3. Company Equipment and Use of Service	7
	4. Indemnification	7
	5. Force Majeure	7-8
V.	General Terms and Conditions	
	1. Agreement	9
	2. Rate Options	9
	3. Rules for Application of Gas Service	9-10
	4. Dispatching	10
	5. Rules Covering Gas Service to Manufactured Homes	10
	6. Consumer Deposits	10-11
	7. Metering and Measurement	12
	8. Measurement Unit for Billing Purposes	12
	9. Unit of Volume for Measurement	12-13
	10. Priority of Service & Allocation of Capacity	13-14

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TABLE OF CONTENTS
GENERAL PROVISIONS Rate 100

Title		Page No.
V.	General Terms and Conditions (cont.)	
	11. Late Payment	14
	12. Returned Check Charge	14
	13. Tax Clause	14
	14. Utility Customer Services	14-15
	15. Utility Services Performed after Normal Business Hours	15
	16. Notice to Discontinue Gas Service	15
	17. Installing Temporary Metering Facilities or Service	16
	18. Reconnection Fee for Seasonal or Temporary Customers	16
	19. Discontinuance of Service for Nonpayment of Bills	16
	20. Discontinuance of Service for Causes other than Nonpayment of Bills	17
	21. Unauthorized Use of Service	18-19
	22. Gas Meter Test by Customer Request	19-20
	23. Additional Rates Identifying Special Provisions	20

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

I. PURPOSE:

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other accepted standards and practices not covered herein. They are intended to ensure adequate service to the public and protect the Company from unreasonable demands.

The Company undertakes to furnish service subject to the rules and regulations of the Public Utilities Commission of South Dakota and as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. DEFINITIONS:

The following terms used in this tariff shall have the following meanings, unless otherwise indicated:

AGENT – The party authorized by the transportation service customer to act on that customer's behalf.

APPLICANT – A customer requesting Company to provide service.

COMMISSION – Public Utilities Commission of the State of South Dakota.

COMPANY – Montana-Dakota Utilities Co. (Montana-Dakota)

COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the customer's convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.

CURTAILMENT – A reduction of transportation or retail natural gas service deemed necessary by the Company. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by the Company at one location and at one point of delivery unless otherwise expressly provided in these rules or in a rate schedule.

DELIVERY POINT – The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of Company's meter(s) located on customer's premises.

GAS DAY – Means a period of twenty-four consecutive hours, beginning and ending at 9:00 A.M. Central Clock Time.

HOUSEHOLD – A family or a group of people who live together.

INDEBTED HOUSEHOLD – A group of people living together among whom there is one who is indebted to a gas utility for service provided previously to the residence for which service is now sought.

INTERRUPTION – A cessation of transportation or retail natural gas service deemed necessary by the Company.

NOMINATION – The daily dk volume of natural gas requested by customer for transportation and delivery to customer at the delivery point during a gas day.

PIPELINE – The transmission company(s) delivering natural gas into company's system.

RATE – Shall mean and include every compensation, charge, fare, toll, rental and classification, or any of them, demanded, observed, charged or collected by the Company for any service, product, or commodity, offered by the Company to the public. This includes any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

RECEIPT POINT – The intertie between the Company and the interconnecting pipeline(s) at which point the Company assumes custody of the gas being transported.

SHIPPER – The party with whom the Pipeline has entered into a service agreement with in order to provide transportation services.

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE – A customer desiring gas service must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. The Company may refuse an applicant or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any person who uses gas service in the absence of an application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

   Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

   Any customer may be asked to make a deposit as required. Pursuant to Rate 100 § V.6.

2. INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates and pressure required for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at the Company's sole discretion, the Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will insure that such equipment will conform to the Company's ability to adequately serve such installations with gas.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

3. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

4. COMPANY PROPERTY – The customers shall exercise reasonable diligence in protecting the Company's property on their premises, and shall be liable to the Company in case of loss or damage caused by their negligence or that of their employees.

5. INTERFERENCE WITH COMPANY PROPERTY – The customer shall not disconnect, change connections, make connections or otherwise interfere with the Company's meters or other property or permit same to be done by other than the Company's authorized employees or representatives.

6. RELOCATED LINES – Where Company facilities are located on a public or private utility easement and customer erects or installs a building, over gas facilities (Company-owned main, Company-owned service line or customer-owned service line) the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

7. NOTIFICATION OF LEAKS – The customer shall immediately notify the Company at its office of any escape of gas in or about the customer's premises.

8. TERMINATION OF GAS SERVICE – All customers are required to notify the Company, to prevent their liability for service used by succeeding tenants, when vacating their premises. Upon receipt of such notice, the Company will read the meter and further liability for service used on the part of the vacating customer will cease.

9. REPORTING REQUIREMENTS – Customer shall furnish the Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

10. QUALITY OF GAS – The gas tendered to the Company shall conform to the applicable quality specifications of the transporting pipeline's tariff.

IV. LIABILITY:

1. CONTINUITY OF SERVICE – The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same except when such loss, injury, death or damage results from the negligence of the Company.

2. CUSTOMER'S EQUIPMENT – Neither by inspection or non-rejection, nor in any other way does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer or leased by the customer from third parties.

3. COMPANY EQUIPMENT AND USE OF SERVICE – The Company will not be liable for any loss, injury, death or damage resulting in any way from the supply or use of gas or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold the Company harmless from any and all injury, death, loss or damage resulting from customer's negligent or wrongful acts under and during the term of service. The Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from the Company's negligent or wrongful acts under and during the term of service.

5. FORCE MAJEURE – In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be

suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of customer's gas are destroyed while in the Company's possession by an event of force majeure, the obligations of the parties shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or the Company, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

V. GENERAL TERMS AND CONDITIONS:

1. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for any service.

2. RATE OPTIONS – Where more than one rate schedule is available for the same class of service, the Company will assist the customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in 12 months unless there is a material change in the customer's load which alters the availability and/or applicability of such rate(s), or unless a change becomes necessary as a result of an order issued by the Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

3. RULES FOR APPLICATION OF GAS SERVICE:
   a. Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, or for the producing operations of a farm or ranch, may be served on the residential rate.

   b. Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty parlors, master metered apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site (this is not an all-inclusive list).

c. The definitions above are based upon the supply of service to an entire premise through a single delivery and metering point. Separate supply for the same customer at other points of consumption may be separately metered and billed.

d. If separate metering is not practical for a single unit (one premise) that is using gas for both domestic purposes and for conducting business (or for nonresidential purposes as defined herein), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the customer's total connected load.

e. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the Nonresidential rates.

4. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by the Company to facilitate transportation service. The Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES – The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Home Construction and Safety Standards) Subpart G and H which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities. This information is available at Montana-Dakota Utilities Co.'s offices.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission rules.

a. The amount of such deposit shall not exceed one-sixth of the estimated annual bill. If a customer has no deposit or one which is inadequate in comparison with his recent bills for service the Company may collect an additional amount in order to bring the total deposit up to the foregoing standard. Should a customer be unable to pay the full amount of the deposit, the Company shall accept payment of the deposit in reasonable installments not to exceed four months.

b. The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall automatically terminate after the customer has established credit that would result in return of a deposit or at the guarantor's request upon sixty days written notice to the Company. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

c. The customer may, in lieu of a deposit, be placed on an early payment list whereby customer shall pay the service bill within a minimum of five working days. However for early payment, early disconnection shall be proper when a customer fails to pay the service bill within a minimum of five working days.

   A deposit shall earn interest at the rate of 7% per year for such period as the customer receives service. Interest shall be credited to the customer's account annually during the month of December.

   Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for 12 months, provided prompt payment record, as defined in the Commission rules, has been established.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

7. METERING AND MEASUREMENT:
   a. The Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. The Company will test meters in accordance with applicable state utility rules and regulations.

   b. Transportation customers agree to provide the cost of the installation of remote data acquisition equipment to the Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the application of a thermal factor to the volumes metered. This thermal factor consists of:

   a. An altitude adjustment factor used to convert metered volumes at local sales base pressure to a standard pressure base of 14.73 psia, and

   b. A Btu adjustment factor used to reflect the heating value of the gas delivered.

9. UNIT OF VOLUME FOR MEASUREMENT – The unit of volume for purpose of measurement shall be one (1) cubic foot of gas at either local sales base pressure or 14.73 psia, as appropriate, and at a temperature base of 60 degrees Fahrenheit (60° F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where

gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AGA-3/NX-19, as amended, supercompressiblity calculation. For hand-billed accounts, application of supercompressibility factors will be waived on monthly-billed volumes of 250 dk or less.

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from highest to lowest:
    a. Priority 1 – Firm sales service.
    b. Priority 2 – Small interruptible sales and small interruptible transportation services at the maximum rate on a pro rata basis.
    c. Priority 3 – Large interruptible sales and large interruptible transportation services at the maximum rate on a pro rata basis.
    d. Priority 4 – Small interruptible sales and small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    e. Priority 5 – Large interruptible sales and large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    f. Priority 6 – Gas scheduled to clear imbalances.

    Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

Montana-Dakota reserves the right to provide service to customers with lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

11. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed.

    All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

12. RETURNED CHECK CHARGE – A charge of $20.00 will be collected by the Company for each check charged back to the Company by a bank.

13. TAX CLAUSE – In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any usage fees or any sales, use, franchise or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

    The charges to be added to the customers' service bills under this clause shall be limited to the customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.

14. UTILITY CUSTOMER SERVICES:
    a. The following services will be performed at no charge regardless of the time of performance:

        1. Fire and explosion calls.

2. Investigate hazardous conditions on customer premises, such as gas leaks, odor complaints, combustible fumes.

3. Maintenance or repair of Company-owned facilities on the customer's premises.

b. The following service calls will be performed at no charge during the Company's normal business hours:

1. Cut-ins and cut-outs.

2. Lighting pilots, inspecting, and adjusting gas equipment in connection with establishing service when working cut-in orders.

3. Investigating high bills or inadequate service complaints.

4. Location of underground Company facilities and customer-owned gas service lines for contractors, builders, plumbers, etc.

15. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours, a charge will be made for labor at standard overtime service rates and materials at retail prices. Customers requesting service after the Company's normal business hours will be informed of the after hour service rate and encouraged to have the service performed during normal business hours.

16. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service discontinued shall notify the Company during regular business hours, one business day before service is to be discontinued. Such notice shall be by letter, personal visit or telephone call to the Company's local business office, in communities in which an office is maintained. In other communities such notice shall be given to the Company's representative who services the community or to the nearest business office. Saturdays, Sundays and legal holidays are not considered business days.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

17. INSTALLING TEMPORARY METERING FACILITIES OR SERVICE – A customer requesting a temporary meter installation and service will be charged on the basis of direct costs incurred by the Company.

18. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS – A customer who requests reconnection of service, during normal business hours at a location where same customer discontinued the same service during the preceding 12-month period will be charged the Basic Service Charge applicable during the period service was not being used or a minimum of $30.00. The minimum will be based on standard overtime rates for reconnecting service after normal business hours.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge of $160.00 whenever reinstallation of the remote data acquisition equipment is necessary.

19. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for services are due when rendered and will be considered delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee of $25.00 before restoring gas service which has been disconnected for nonpayment of service bills during normal business hours. Standard overtime rates will apply for services performed after normal business hours.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

20. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS – The Company reserves the right to discontinue service for any of the following reasons:

    a. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

    b. In the event of tampering with the equipment furnished and owned by the Company.

    c. For violation of, or noncompliance with, the Company's rules on file with the Commission.

    d. For failure of the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

    e. For refusal of reasonable access to property to the agent or employee of the Company for the purpose of inspecting the facilities or for testing, reading, maintaining or removing meters.

    The right to discontinue service for any of the above reasons may be exercised whenever and as often as such reasons may occur, and any delay on the part of the Company in exercising such rights, or omission of any action permissible hereunder, shall not be deemed a waiver of its rights to exercise same.

    Nothing in these regulations shall be construed to prevent discontinuing service without advance notice for reasons of safety, health, cooperation with civil authorities, or fraudulent use, tampering with or destroying the Company's facilities.

    The Company may collect a reconnect fee of $30.00 before restoring gas service which has been disconnected for the above causes.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

21. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as tampering with the Company's meter, pressure regulator, registration, connections, equipment, seals, valve, procedures or records resulting in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service that has been terminated, without the Company's consent.

    a. Examples of unauthorized use of service includes, but is not limited to, tampering or unauthorized reconnection by the following methods:

        1. Bypass piping around meter.
        2. Bypass piping installed in place of meter.
        3. Meter reversed.
        4. Meter index disengaged or removed.
        5. Service or equipment tampered with or piping connected ahead of meter.
        6. Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
        7. Gas being used after service has been discontinued by the Company.
        8. Gas being used after service has been discontinued by the Company as a result of a new customer turning gas on without the proper connect request.

    b. Any charges for damage to Company property will be billed to the customer. The customer may also be charged for:

        1. Time, material and transportation costs used in investigation or surveillance.
        2. Estimated charge for non-metered gas.
        3. On-premise time to correct situation.
        4. A minimum fee of $30.00 will apply.

        All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company.

c. Reconnection of Service:
Gas service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service, and paid any service charges which are due, including:

1. All delinquent bills, if any.
2. The amount of any Company revenue loss attributable to said tampering.
3. Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in paragraph 20.b.above;
4. Reconnection fee applicable.
5. A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with §V, paragraph 6 CONSUMER DEPOSITS.

22. GAS METER TEST BY CUSTOMER REQUEST - Any customer may request the Company to test its gas meter. The Company shall make the test as soon as possible after receipt of the request. If a request is made within one year after a previous request, the Company may require a deposit as follows:

Meter Rating	Deposit Amount
Residential	
All	$10.00
Non-Residential	
425 CFH* or less	$40.00
426 CFH to 1000 CFH	$40.00
Over 1000 CFH	$70.00

* Cubic feet per hour

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

The deposit shall be refunded only if the meter is found to have an unacceptable error, as defined in the Commission's regulations. In the case where a meter is replaced due to malfunction, a customer will be allowed one additional free meter test within 12 months, if requested by the customer.

23. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
    - Rate 102 - Residential Rate for Regular Employees
    - Rate 119 - Interruptible Gas Service Extension Policy
    - Rate 120 - Firm Gas Service Extension Policy
    - Rate 124 - New Installation, Replacement, Relocation and Repair of Gas Service Lines
    - Rate 134 - Rules and Policies for Implementing Master Metering Restrictions

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule

Section No. 5
1st Revised Sheet No. 24
Canceling Original Sheet No. 24

NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

1. The Company will install, at its expense, a service line extending from the main to the connection at the premise regulator and/or meter for all customers. The service line installed by the Company will remain the Company's property. D

2. A non-refundable contribution may be required for that portion of the service line cost not supported by the expected or actual connected load. The contribution requirement will be determined based on minimum footage allowances determined annually taking into account the maximum allowable investment defined in Rate 120 and the statewide average installed per foot cost. The Company reserves the right to charge customer the total cost of the installed service line if service is not initiated within 12 months of such installation.

3. The portion of the service line not cost justified shall be charged to the customer on the basis of direct costs to the Company. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply.

4. Where service line location changes are required due to building encroachments (a building is being constructed or is already located over a service line, etc.) or due to a customer request to move a service line, the customer shall be charged on the basis of direct costs incurred by the Company.

5. Whenever a service line is damaged by the customer or someone under the employ of the customer necessitating the service line to be either repaired or replaced in whole or in substantial part, such work shall be charged for on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

6. Service line changes necessary to increase the size and capacity of an existing service line because of increased demand shall be treated in accordance with paragraph 2 above.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 5
Canceling Original Sheet No. 5

DISCONNECT NOTICE

MONTANA-DAKOTA UTILITIES CO

Account Number: _____

DISCONNECT NOTICE

WE WANT TO CONTINUE OUR DEPENDABLE SERVICE TO YOU,
OUR VALUED CUSTOMER, BUT YOU MUST TAKE ACTION NOW.

Date:

Service Address:

Payment of your service account is now past due. Your service will be disconnected on _____ unless your past due amount is paid in full or satisfactory arrangements are made before this date. If service is disconnected, payment in full and a reconnect fee of _____ plus applicable taxes to restore service during normal working hours, plus a deposit or additional deposit of _____ will be required before service is restored.

PLEASE CONTACT US NOW TO AVOID ANY INCONVENIENCE
THANK YOU.

	PAST DUE	CURRENT	ACCT BALANCE
UTILITY:			
DEPOSIT:	$0.00	$0.00	$0.00

DIRECT INQUIRIES TO:
MONTANA-DAKOTA UTILITIES CO
PO BOX 1060
RAPID CITY SD 57709
1 605 342 0187

DIRECT PAYMENTS TO:
MONTANA-DAKOTA UTILITIES CO
PO BOX 5600
BISMARCK ND 58506-5600

DIRECT UNRESOLVED COMPLAINTS TO:
SD PUBLIC UTILITIES COMMISSION
500 E CAPITOL
PIERRE SD 57501
1 800 332 1782

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 8
Canceling Original Sheet No. 8

DISCONTINUANCE NOTICE FOR UNAUTHORIZED USE OF SERVICE

MONTANA-DAKOTA UTILITIES CO.
DISCONTINUANCE NOTICE

NOTICE TO CUSTOMER:

Today we inspected your gas/electric service installation. This inspection has revealed that you are obtaining unauthorized gas/electric service at the address shown below. Under rules and regulations filed with, and approved by, the Public Utility Commission of _____, service can be terminated because of this irregularity. To avoid discontinuance of service bring this card to our office, no later than _____, at the address shown below, and we will discuss the conditions under which your gas/electric service will not be interrupted.

MONTANA-DAKOTA UTILITIES CO.
Address: _____
_____
Telephone No.: _____

Date: _____
Customer: _____
Address: _____
_____
Meter No.: _____
Employee: _____

Date Filed: June 7, 2004 **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.: NG04-___

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS

MONTANA-DAKOTA UTILITIES CO.
DISCONTINUANCE NOTICE

NOTICE TO CUSTOMER:
Today we inspected your gas/electric service installation and under rules and regulations filed with, and approved by, the Public Utility Commission of _____, we are legally authorized to discontinue service due to an irregularity. In order to have your service restored, bring this card to our office, at the address shown below, and we will discuss the conditions under which gas/electric service may be restored.

MONTANA-DAKOTA UTILITIES CO.
Address: _____
_____
Telephone No.: _____

Date: _____
Customer: _____
Address: _____
_____
Meter No.: _____
Employee: _____

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 13
Canceling Original Sheet No. 13

GUARANTEE OF PAYMENT FOR NATURAL GAS AND/OR ELECTRIC SERVICE BY A SECOND PARTY IN LIEU OF A DEPOSIT

GUARANTEE OF PAYMENT FOR NATURAL GAS AND/OR
ELECTRIC SERVICE BY A SECOND PARTY IN LIEU OF A DEPOSIT

304406-04
Rev. 0403

MONTANA-DAKOTA UTILITIES CO.
GUARANTEE OF PAYMENT FOR
NATURAL GAS AND/OR ELECTRIC SERVICE

_____
(Date)

To: Montana-Dakota Utilities Co.

_____
(Address)

_____
(City, State, Zip Code)

For value received, I, _____, do hereby absolutely guarantee to pay to
(Name of Guarantor)
Montana-Dakota Utilities Co. (Montana-Dakota), upon its request and at the location listed above, the outstanding balance accrued by _____ in the event that Customer's bill for natural gas and/or
(Name of Customer)
electricity provided by Montana-Dakota at _____ is not paid
(Customer's Service Address)
when due; however, liability under this Guarantee, other than the collection costs noted below, shall not exceed the sum of $ _____. As Guarantor, I request copies of all disconnect notices sent to the Customer.

Liability under this Guarantee shall begin on _____, 19____, and shall continue until Customer has paid for natural gas and/or electric service when due in a prompt and satisfactory manner for twelve consecutive months in accordance with Public Service Commission or Public Utilities Commission rules. I expressly waive receipt of notice of Montana-Dakota's acceptance of my guarantee.

I also agree to pay any and all costs that Montana-Dakota may incur in the collection of this guarantee. In the event legal action is required or becomes necessary to collect the outstanding balance accrued by the Customer from me under this guarantee, I agree to pay all legal fees, including attorneys' fees, in the amount the court determines is reasonable.

I ACKNOWLEDGE THAT I HAVE CAREFULLY READ THE ABOVE GUARANTEE AGREEMENT AND THAT I HAVE RECEIVED A COPY OF IT.

GUARANTOR:

_____
(Signature of Witness)

_____
(Signature of Guarantor)

_____
(Guarantor's Mailing Address)

_____
(Guarantor's Street Address—If Different than Mailing Address)

_____
(City, State, Zip Code)

_____
(Guarantor's Telephone Number)

DIVISION OFFICE – White Copy CUSTOMER COPY – Yellow Copy GUARANTOR COPY – Pink Copy

Date Filed:	June 7, 2004	**Effective Date:**	
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		
Docket No.:	NG04-___		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 16
Canceling Original Sheet No. 16

FINAL NOTICE PRIOR TO DISCONNECT

MONTANA-DAKOTA UTILITIES CO

Account Number: _____

FINAL NOTICE

WE WANT TO CONTINUE OUR DEPENDABLE SERVICE TO YOU,
OUR VALUED CUSTOMER, BUT YOU MUST TAKE ACTION NOW.

Date:

Service Address:

YOUR SERVICE ACCOUNT IS SERIOUSLY PAST DUE.

THIS IS YOUR FINAL NOTIFICATION THAT YOUR GAS AND/OR ELECTRIC SERVICE WILL BE DISCONTINUED IMMEDIATELY -

Unless your past due amount is paid in full or satisfactory arrangements are made in person to the CREDIT DEPARTMENT of MONTANA-DAKOTA UTILITIES CO. by 5:00 p.m. on _____.

If service is disconnected, payment in full and a reconnect fee of _____ to restore service during normal working hours plus a deposit or additional deposit of will be required before service is restored.

PLEASE CONTACT US NOW TO AVOID ANY INCONVENIENCE
THANK YOU.

	PAST DUE	CURRENT	ACCT BALANCE
UTILITY:			
DEPOSIT:	$0.00	$0.00	$0.00

DIRECT INQUIRIES TO:
MONTANA-DAKOTA UTILITIES CO
PO BOX 1060
RAPID CITY SD 57709
1 605 342 0187

DIRECT UNRESOLVED COMPLAINTS TO:
SD PUBLIC UTILITIES COMMISSION
500 E CAPITOL
PIERRE SD 57501
1 800 332 1782

Tariffs Reflecting Proposed Changes

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 1
Original Sheet No. 1
TABLE OF CONTENTS Canceling Vol. 1 15th Rev. Sheet No. 1

Designation	Title	Sheet No.
Section No. 1	Table of Contents	1
Section No. 2	Preliminary Statement	1
Section No. 3	Rate Schedules	
	Rate Summary Sheet	1
Rate 60	Residential Gas Service	2
	Reserved for Future Use	3-4
Rate 64	Ellsworth Air Force Base	5
	Reserved for Future Use	6
Rate 66	East River Natural Gas System General Services	7
	Reserved for Future Use	8-10
Rate 70	Firm General Gas Service	11
Rate 71	Small Interruptible General Gas Service	12
Rate 72	Optional Seasonal General Gas Service	13
	Reserved for Future Use	14-21
Rate 81 and 82	Transportation Service	22
	Reserved for Future Use	23-25
Rate 85	Large Interruptible General Gas Service	26
	Reserved for Future Use	27
Rate 87	Distribution Delivery Stabilization Mechanism	28
Rate 88	Purchased Gas Cost Adjustment	29
Rate 89	East River Natural Gas System Purchase Gas Cost Adjustment	30
Section No. 4	List of Contracts with Deviations	1
Section No. 5	Rules	
Rate 100	General Provisions	1
	Reserved for Future Use	2
Rate 102	Residential Rate for Regular Employees	3
	Reserved for Future Use	4-18
Rate 119	Interruptible Gas Service Extension Policy	19
Rate 120	Firm Gas Service Extension Policy	20
	Reserved for Future Use	21-23

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TABLE OF CONTENTS

Rate 124	New Installation, Replacement, Relocation and Repair of Gas Service Lines	24
	Reserved for Future Use	25-33
Rate 134	Rules and Policies for Implementing Master Metering Restrictions	34
Section No. 6	Sample Forms	
	Consumer's Deposit Receipt	1
	New Customer Application Card	2
	Gas Meter Order	3
	Standard Customer Bill	4
	Disconnect Notice	5
	Application for Interruptible Natural Gas Service	6
	Customer Information Booklet	7
	Discontinuance Notices for Causes Other Than Nonpayment of Bills ~~Unauthorized Use of Service~~	8
	Third Party Notice	9
	Deferred Installment Agreement Form	10
	Agreement by Property Owner or Agent to Pay Utility Bills During Periods When Property is Unoccupied	11
	~~Form Advising Property Owner Tenant is Vacating Premises and Service Has Been Connected in Property Owner's Name per an Agreement~~ Reserved for Future Use	12
	Guarantee of Payment for Natural Gas and/or Electric Service by a Second Party in Lieu of a Deposit	13
	Deposit Warning Letter	14
	Deposit Request	15
	Final Notice Prior to Disconnect	16
	Interruptible General Gas Service Agreement	17
	Request for Firm Natural Gas Sales Service	18
	Gas Transportation Agreement	19
	Customers Agreement for Gas Extension	20
	Gas Service Order	21
	Facilities Relocation Agreement	22
	Warning Notice	23
	Temporary Construction Heat Agreement	24

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 2
Canceling Vol. 1 19th Rev. Sheet No. 1

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served, except for those communities set forth on Rate 66, for all domestic uses. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	~~$0.25~~ $0.26 per day
Distribution Delivery Charge:	~~$1.4351~~ $1.666 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

General Terms and Conditions:

RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 11
Canceling Vol. 1 2nd Rev. Sheet No. 11

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served, except for those communities set forth on Rate 66, for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.~~3335~~ per day
For customers with meters rated over 500 cubic feet per hour	$0.~~66~~70 per day
Distribution Delivery Charge:	~~$1.078~~1.226 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 13
Canceling Vol. 1 2nd Rev. Sheet No. 13

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served, except for those communities set forth on Rate 66, for customers otherwise qualifying for service under Firm General Gas Service Rate 70. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.~~3335~~ per day
For customers with meters rated over 500 cubic feet per hour	$0.~~6670~~ per day
Distribution Delivery Charge:	$~~1.0781~~.226 per dk
Cost of Gas:	
Winter – Bills rendered October 1 through ~~March~~May 31	Determined Monthly – See Rate Summary Sheet for Current Rate
Summer – Bills rendered ~~April~~June 1 through September 30	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
Original Sheet No. 26
Canceling Vol. 1 1st Rev. Sheet No. 26

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served, except those communities set forth on Rate 66, for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will exceed 40,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement. The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

This rate schedule shall not apply for service to U. S. Government installations, which are covered by separate special contracts.

Rate:

Basic Service Charge:	~~$150.00~~175.00 per month
Distribution Delivery Charge:	
Maximum Rate	$0.~~177~~ .183per dk
Minimum Rate	$0.090 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TRANSPORTATION SERVICE Rates 81 and 82

Rate:

Basic Service Charge:
Rate 81 $125.00 per month 1/
Rate 82 ~~$200.00~~225.00 per month 2/

1/ In the event customer takes service through one meter under both Rates 71 and 81, the base rate under Rate 81 shall be waived.

2/ In the event customer takes service through one meter under both Rates 85 and 82, the base rate under Rate 82 shall be waived.

Under Rates 81 or 82 customer shall pay a negotiated rate not more than the maximum rate or less than the minimum rate specified below. (The per dk charge is applicable to all dk of natural gas transported under the terms of this rate.)

	Rate 81	Rate 82
Maximum Rate per dk	$0.453	$0.~~177~~183
Minimum Rate per dk	$0.131	$0.090
Balancing Charge per dk	$0.300	$0.300

Fuel Charge:
Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See Rate Summary Sheet for currently effective charge.

GENERAL TERMS AND CONDITIONS:

1. CRITERIA FOR SERVICE – In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. The customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 1
Canceling Vol. 1 1st Rev. Sheet No. 1

TABLE OF CONTENTS
GENERAL PROVISIONS Rate 100

Title		Page No.
I.	Purpose	3
II.	Definitions	3-4
III.	Customer Obligations	
	1. Application for Service	5
	2. Input Rating	5
	3. Access to Customer's Premises	6
	4. Company Property	6
	5. Interference with Company Property	6
	6. Relocated Lines	6
	7. Notification of Leaks	6
	8. Termination of Gas Service	6
	9. Reporting Requirement	6
	10. Quality of Gas	6
IV.	Liability	
	1. Continuity of Service	7
	2. Customer's Equipment	7
	3. Company Equipment and Use of Service	7
	4. Indemnification	7
	5. Force Majeure	7-8
V.	General Terms and Conditions	
	1. Agreement	9
	2. Rate Options	9
	3. Rules for Application of Gas Service	9-10
	4. Dispatching	10
	5. Rules Covering Gas Service to Manufactured Homes	10
	6. Consumer Deposits	10-11
	7. Metering and Measurement	12
	8. Measurement Unit for Billing Purposes	12
	9. Unit of Volume for Measurement	13
	10. Priority of Service & Allocation of Capacity	13-14

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
Original Sheet No. 1.1
Canceling Vol. 1 1st Rev. Sheet No. 1.1

TABLE OF CONTENTS
GENERAL PROVISIONS Rate 100

Title		Page No.
V.	General Terms and Conditions(cont.)	
	11. Late Payment	14
	12. Returned Check Charge	14
	13. Tax Clause	14
	14. Utility Customer Services	15
	15. Utility Services Performed after Normal Business Hours	15
	16. Notice to Discontinue Gas Service	16
	17. Installing Temporary Metering Facilities or Service	16
	18. Reconnection Fee for Seasonal or Temporary Customers	16
	19. ~~Disconnection~~Discontinuance of Service for Nonpayment of Bills	16
	20. ~~Disconnection~~Discontinuance of Service for Causes other than Nonpayment of Bills	17
	21. Unauthorized Use of Service	18-19
	22. Gas Meter Test by Customer Request	19-20
	23. Additional Rates Identifying Special Provisions	20

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
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Docket No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

I. PURPOSE:

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other accepted standards and practices not covered herein. They are intended to ensure adequate service to the public and protect the Company from unreasonable demands.

The Company undertakes to furnish service subject to the rules and regulations of the Public Utilities Commission of South Dakota and as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. DEFINITIONS:

The following terms used in this tariff shall have the following meanings, unless otherwise indicated:

AGENT – The party authorized by the transportation service customer to act on that customer's behalf.

APPLICANT – A customer requesting Company to provide service.

COMMISSION – Public Utilities Commission of the State of South Dakota.

COMPANY – Montana-Dakota Utilities Co. (Montana-Dakota)

COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the customer's convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.

CURTAILMENT – A reduction of transportation or retail natural gas service deemed necessary by the Company. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by the Company at one location and at one point of delivery unless otherwise expressly provided in these rules or in a rate schedule.

DELIVERY POINT – The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of Company's meter(s) located on customer's premises.

GAS DAY – Means a period of twenty-four consecutive hours, beginning and ending at 9:00 A.M. Central Clock Time.

HOUSEHOLD – A family or a group of people who live together.

INDEBTED HOUSEHOLD – A group of people living together among whom there is one who is indebted to a gas utility for service provided previously to the residence for which service is now sought.

INTERRUPTION – A cessation of transportation or retail natural gas service deemed necessary by the Company.

NOMINATION – The daily dk volume of natural gas requested by customer for transportation and delivery to customer at the delivery point during a gas day.

PIPELINE – The transmission company(s) delivering natural gas into company's system.

RATE – Shall mean and include every compensation, charge, fare, toll, rental and classification, or any of them, demanded, observed, charged or collected by the Company for any service, product, or commodity, offered by the Company to the public. ~~, and~~ This includes any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

RECEIPT POINT – The intertie between the Company and the interconnecting pipeline(s) at which point the Company assumes custody of the gas being transported.

SHIPPER – The party with whom the Pipeline has entered into a service agreement with in order to provide~~for~~ transportation services.

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE – A customer desiring gas service must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. The Company may refuse ~~a customer~~ an applicant or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any ~~customer~~person who uses gas service in the absence of an application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

   Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

   Any customer may be asked to make a deposit as required. Pursuant to Rate 100 § V.6.

2. INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates and pressure required for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at the Company's sole discretion, the Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will insure that such equipment will conform to the Company's ability to adequately serve such installations with gas.

3. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

4. COMPANY PROPERTY – The customers shall exercise reasonable diligence in protecting the Company's property on their premises, and shall be liable to the Company in case of loss or damage caused by their negligence or that of their employees.

5. INTERFERENCE WITH COMPANY PROPERTY – The customer shall not disconnect, change connections, make connections or otherwise interfere with the Company's meters or other property or permit same to be done by other than the Company's authorized employees or representatives.

6. RELOCATED LINES – Where Company facilities are located on a public or private utility easement and customer erects or installs a building, over gas facilities (Company-owned main, Company-owned service line or customer-owned service line) the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

7. NOTIFICATION OF LEAKS – The customer shall immediately notify the Company at its office of any escape of gas in or about the customer's premises.

8. TERMINATION OF GAS SERVICE – All customers are required to notify the Company, to prevent their liability for service used by succeeding tenants, when vacating their premises. Upon receipt of such notice, the Company will read the meter and further liability for service used on the part of the vacating customer will cease.

9. ~~9.~~—REPORTING REQUIREMENTS – Customer shall furnish the Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

10. QUALITY OF GAS – The gas tendered to the Company shall conform to the applicable quality specifications of the transporting pipeline's tariff.

IV. LIABILITY:

1. CONTINUITY OF SERVICE – The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same except when such loss, injury, death or damage results from the negligence of the Company.

2. CUSTOMER'S EQUIPMENT – Neither by inspection or non-rejection, nor in any other way does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer or leased by the customer from third parties.

3. COMPANY EQUIPMENT AND USE OF SERVICE – The Company will not be liable for any loss, injury, death or damage resulting in any way from the supply or use of gas or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold the Company harmless from any and all injury, death, loss or damage resulting from customer's negligent or wrongful acts under and during the term of service. The Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from the Company's negligent or wrongful acts under and during the term of service.

5. FORCE MAJEURE – In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused. Such causes or

contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of customer's gas are destroyed while in the Company's possession by an event of force majeure, the obligations of the parties shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or the Company, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS:

1. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for any service.

2. RATE OPTIONS – Where more than one rate schedule is available for the same class of service, the Company will assist the customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in ~~twelve~~12 months unless there is a material change in the customer's load which alters the availability and/or applicability of such rate(s), or unless a change becomes necessary as a result of an order issued by the Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

3. RULES FOR APPLICATION OF GAS SERVICE:
   a. Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, or for the producing operations of a farm or ranch, may be served on the residential rate.

   b. Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty parlors, master metered apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site (this is not an all-inclusive list).

c. The definitions above are based upon the supply of service to an entire premise through a single delivery and metering point. Separate supply for the same customer at other points of consumption may be separately metered and billed.

d. If separate metering is not practical for a single unit (one premise) that is using gas for both domestic purposes and for conducting business (or for nonresidential purposes as defined herein), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the customer's total connected load.

e. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the Nonresidential rates.

4. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by the Company to facilitate transportation service. The Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES – The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Home Construction and Safety Standards) Subpart G and H which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities. This information is available at Montana-Dakota Utilities Co.'s offices.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with eCommission rules.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

a. The amount of such deposit shall not exceed one-sixth of the estimated annual bill. If a customer has no deposit or one which is inadequate in comparison with his recent bills for service the Company may collect an additional amount in order to bring the total deposit up to the foregoing standard. Should a customer be unable to pay the full amount of the deposit, the Company shall accept payment of the deposit in reasonable installments not to exceed four months.

b. The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall automatically terminate after the customer has established credit that would result in return of a deposit or at the guarantor's request upon sixty days written notice to the Company. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

c. The customer may, in lieu of a deposit, be placed on an early payment list whereby customer shall pay the service bill within a minimum of five working days. However for early payment, early disconnection shall be proper when a customer fails to pay the service bill within a minimum of five working days.

A deposit shall earn interest at the rate of 7% per year for such period as the customer receives service. Interest shall be credited to the customer's account annually during the month of December.

Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for ~~twelve~~12 months, provided prompt payment record, as defined in the Commission rules, ~~satisfactory credit~~ has been established.

7. METERING AND MEASUREMENT:
   a. The Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. The Company will test meters in accordance with applicable state utility rules and regulations.

   b. Transportation customers agree to provide the cost of the installation of remote data acquisition equipment to the Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the application of a thermal factor to the volumes metered. This thermal factor consists of:

   a. An altitude adjustment factor used to convert metered volumes at local sales base pressure to a standard pressure base of 14.73 psia, and

   b. A Btu adjustment factor used to reflect the heating value of the gas delivered.

9. UNIT OF VOLUME FOR MEASUREMENT – The unit of volume for purpose of measurement shall be one (1) cubic foot of gas at either local sales base pressure or 14.73 psia, as appropriate, and at a temperature base of ~~sixty~~60 degrees Fahrenheit (60° F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where

gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AGA-3/NX-19, as amended, supercompressiblity calculation. For hand billed accounts, application of ~~S~~supercompressibility factors ~~adjustments~~ will be waived on monthly ~~-~~billed volumes of 250 dk or less.

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from ~~H~~highest to ~~L~~lowest:
    a. Priority 1 – Firm sales service.
    b. Priority 2 – Small interruptible sales and small interruptible transportation services at the maximum rate on a pro rata basis.
    c. Priority 3 – Large interruptible sales and large interruptible transportation services at the maximum rate on a pro rata basis.
    d. Priority 4 – Small interruptible sales and small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    e. Priority 5 – Large interruptible sales and large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    f. Priority 6 – Gas scheduled to clear imbalances.

    Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

Montana-Dakota reserves the right to provide service to customers with ~~a~~ lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

11. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed.–

    All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

12. RETURNED CHECK CHARGE – A charge of $20.00 will be collected by the Company for each check charged back to the Company by a bank.

13. TAX CLAUSE – In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any usage fees or any sales, use, franchise or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

    The charges to be added to the customers' service bills under this clause shall be limited to the customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.

14. UTILITY CUSTOMER SERVICES:
    a. The following services will be performed at no charge regardless of the time of performance:

        1. Fire and explosions calls.

2. Investigate hazardous conditions on customer premises, such as gas leaks, odor complaints, combustible fumes.

3. Maintenance or repair of Company-owned facilities on the customer's premises.

b. The following service calls will be performed at no charge during the Company's normal business hours:

1. Cut-ins and cut-outs.

2. Lighting pilots, inspecting, and adjusting gas equipment in connection with establishing service when working cut-in orders.

3. Investigating ~~H~~high bills or inadequate service complaints.

4. Location of underground Company facilities and customer-owned gas service lines for contractors, builders, plumbers, etc.

~~5. Service calls for routine cut-ins, when the order is received prior to 12:00 P.M. on a regular work day will be considered as non-chargeable regardless if work is performed outside of normal working hours.~~

15. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours, a charge will be made for labor at standard overtime service rates and materials at retail prices. Customers requesting service after the Company's normal business hours will be informed of the after hour service rate and encouraged to have the service performed during normal business hours.

16. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service discontinued shall notify the Company during regular business hours, one business day before service is to be ~~disconnected.~~discontinued. Such notice shall be by letter, personal visit or telephone call to the Company's local business office, in communities

in which an office is maintained. In other communities such notice shall be given to the Company's representative who services the community or to the nearest business office. Saturdays, Sundays and legal holidays are not considered business days.

17. INSTALLING TEMPORARY METERING FACILITIES OR SERVICE – A customer requesting a temporary meter installation and service will be charged on the basis of direct costs incurred by the Company.

18. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS – A customer who requests reconnection of service, during normal business hours at a location where same customer discontinued the same service during the preceding 12-month period will be charged the Basic Service Charge applicable during the period service was not being used or a minimum of $30.00. ~~during normal business hours.~~ The minimum will be based on standard overtime rates for reconnecting service after normal business hours.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge of $160.00 whenever reinstallation of the remote data acquisition equipment is necessary.

19. ~~DISCONNECTION~~DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for services are due when rendered and will be considered delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee of $25.00 before restoring gas service which has been disconnected for nonpayment of service bills during normal business hours. Standard overtime rates will apply for services performed after normal business hours.

20. ~~DISCONNECTION~~ DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS – The Company reserves the right to discontinue service for any of the following reasons:

    a. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

    b. In the event of tampering with the equipment furnished and owned by the Company.

    c. For violation of, or noncompliance with, the Company's rules on file with the Commission.

    d. For failure of the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

    e. For refusal of reasonable access to property to the agent or employee of the Company for the purpose of inspecting the facilities or for testing, reading, maintaining or removing meters.

    The right to discontinue service for any of the above reasons may be exercised whenever and as often as such reasons may occur, and any delay on the part of the Company in exercising such rights, or omission of any action permissible hereunder, shall not be deemed a waiver of its rights to exercise same.

    Nothing in these regulations shall be construed to prevent discontinuing service without advance notice for reasons of safety, health, cooperation with civil authorities, or fraudulent use, tampering with or destroying the Company's facilities.

    The Company may collect a reconnect fee of $30.00 before restoring gas service which has been disconnected for the above causes.

21. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as~~or~~ tampering with ~~a~~the Company's meter, pressure regulator, registration, connections, equipment, seals, valve, procedures or records resulting in a loss of revenue to the Company. Unauthorized service ~~includes~~ is also defined as reconnection of service~~,~~ that has been terminated, without the Company's consent.

    a. ~~Types~~Examples of unauthorized use of service includes, but is not limited to, tampering or unauthorized reconnection by the following methods:

        1. Bypass piping around meter.
        2. Bypass piping installed in place of meter.
        3. Meter reversed.
        4. Meter index disengaged or removed.
        5. Service or equipment tampered with or piping connected ahead of meter.
        6. Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
        7. Gas being used after service has been discontinued by the Company.
        8. Gas being used after service has been discontinued by the Company as a result of a new customer turning gas on without the proper connect request.

    b. Any charges for damage to Company property will be billed to the customer. The customer may also be charged for:

        1. Time, material and transportation costs used in investigation or surveillance.
        2. Estimated charge for non-metered gas.
        3. On-premise time to correct situation.
        4. A minimum fee of $30.00 will apply.

        All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company.

c. Reconnection of Service:
~~Customer~~Gas service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service, and paid any service charges which are due, including:

1. All delinquent bills, if any~~;~~.
2. The amount of any Company revenue loss attributable to said ~~unauthorized use of service;~~tampering.
3. Expenses incurred by the Company in replacing or repairing the meter or other appliance~~,~~ costs incurred in preparation of the bill, plus ~~and~~ costs as outlined in paragraph ~~b.~~20.b.above;
4. Reconnection fee applicable~~;and~~.
5. A ~~C~~cash deposit, the amount of which will not exceed the maximum amount determined in accordance with §V, paragraph 6 CONSUMER DEPOSITS.

22. GAS METER TEST BY CUSTOMER REQUEST - Any customer may request the Company to test its gas meter. The Company shall make the test as soon as possible after receipt of the request. If a request is made within one year after a previous request, the Company may require a deposit as follows:

Meter Rating	Deposit Amount
Residential	
All	$10.00
Non-Residential	
425 CFH* or less	$40.00
426 CFH to 1000 CFH	$40.00
Over 1000 CFH	$70.00

* Cubic feet per hour

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

The deposit shall be refunded only if the meter is found to have an un-acceptable error, as defined in the Commission's regulations. In the case where a meter is replaced due to malfunction, a customer will be allowed one additional free meter test within 12 months, if requested by the customer.

23. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
    - Rate 102 - Residential Rate for Regular Employees
    - Rate 119 - Interruptible Gas Service Extension Policy
    - Rate 120 - Firm Gas Service Extension Policy
    - Rate 124 - New Installation, Replacement, Relocation and Repair of Gas Service Lines
    - Rate 134 - Rules and Policies for Implementing Master Metering Restrictions

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule

SD P.U.C. Section No. 5
Original Sheet No. 24
Canceling Vol. 1 Original Sheet No. 24

NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

1. The Company will install, at its expense, a service line extending from the main to the connection at the premise regulator and/or meter for all customers. ~~connected on and after (effective date of tariff) and all replacement service lines installed on and after (effective date of tariff).~~ The service line installed by the Company will remain the Company's property.

2. A non-refundable contribution may be required for that portion of the service line cost not supported by the expected or actual connected load. The contribution requirement will be determined based on minimum footage allowances determined annually taking into account the maximum allowable investment defined in Rate 120 and the statewide average installed per foot cost. The Company reserves the right to charge customer the total cost of the installed service line if service is not initiated within 12 months of such installation.

3. The portion of the service line not cost justified shall be charged to the customer on the basis of direct costs to the Company. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply.

4. Where service line location changes are required due to building encroachments (a building is being constructed or is already located over a service line, etc.) or due to a customer request to move a service line, the customer shall be charged on the basis of direct costs incurred by the Company.

5. Whenever a service line is damaged by the customer or someone under the employ of the customer necessitating the service line to be either repaired or replaced in whole or in substantial part, such work shall be charged for on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

6. Service line changes necessary to increase the size and capacity of an existing service line because of increased demand shall be treated in accordance with paragraph 2 above.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 5
Canceling Vol. 1 4th Rev. Sheet No. 6

DISCONNECT NOTICE

MONTANA-DAKOTA UTILITIES CO

OM

Account Number: _____

DISCONNECT NOTICE

WE WANT TO CONTINUE OUR DEPENDABLE SERVICE TO YOU,
OUR VALUED CUSTOMER, BUT YOU MUST TAKE ACTION NOW.

Date:

Service Address:

Payment of your service account is now past due. Your service will be disconnected on _____ unless your past due amount is paid in full or satisfactory arrangements are made before this date. If service is disconnected, payment in full and a reconnect fee of _____ plus applicable taxes to restore service during normal working hours, plus a deposit or additional deposit of _____ will be required before service is restored.

PLEASE CONTACT US NOW TO AVOID ANY INCONVENIENCE
THANK YOU.

	PAST DUE	CURRENT	ACCT BALANCE
UTILITY:			
DEPOSIT:	$0.00	$0.00	$0.00

DIRECT INQUIRIES TO:
MONTANA-DAKOTA UTILITIES CO
PO BOX 1060
RAPID CITY SD 57709
1 605 342 0187

DIRECT PAYMENTS TO:
MONTANA-DAKOTA UTILITIES CO
PO BOX 5600
BISMARCK ND 58506-5600

DIRECT UNRESOLVED COMPLAINTS TO:
SD PUBLIC UTILITIES COMMISSION
500 E CAPITOL
PIERRE SD 57501
1 800 332 1782

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 8
Canceling Vol. 1 Original Sheet No. 9

DISCONTINUANCE NOTICE FOR UNAUTHORIZED USE OF SERVICE

MONTANA-DAKOTA UTILITIES CO.
DISCONTINUANCE NOTICE

NOTICE TO CUSTOMER:

Today we inspected your gas/electric service installation. This inspection has revealed that you are obtaining unauthorized gas/electric service at the address shown below. Under rules and regulations filed with, and approved by, the Public Utility Commission of _____, service can be terminated because of this irregularity. To avoid discontinuance of service bring this card to our office, no later than _____, at the address shown below, and we will discuss the conditions under which your gas/electric service will not be interrupted.

MONTANA-DAKOTA UTILITIES CO.
Address: _____
_____
Telephone No.: _____

Date: _____
Customer: _____
Address: _____
_____
Meter No.: _____
Employee: _____

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS

MONTANA-DAKOTA UTILITIES CO.
DISCONTINUANCE NOTICE

NOTICE TO CUSTOMER:
Today we inspected your gas/electric service installation and under rules and regulations filed with, and approved by, the Public Utility Commission of _____, we are legally authorized to discontinue service due to an irregularity. In order to have your service restored, bring this card to our office, at the address shown below, and we will discuss the conditions under which gas/electric service may be restored.

MONTANA-DAKOTA UTILITIES CO.
Address: _____
_____
Telephone No.: _____

Date: _____
Customer: _____
Address: _____
_____
Meter No.: _____
Employee: _____

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 12
Canceling Vol. 1 Original Sheet No. 15

~~FORM ADVISING PROPERTY OWNER TENANT IS VACATING PREMISES AND SERVICE HAS BEEN CONNECTED IN PROPERTY OWNER'S NAME PER AN AGREEMENT~~

FORM ADVISING PROPERTY OWNER TENANT IS VACATING PREMISES AND SERVICE HAS BEEN CONNECTED IN PROPERTY OWNER'S NAME PER AN AGREEMENT

208111B-78I
(Rev. 12/88)

FOR YOUR INFORMATION

Your tenant, _____, has advised us that he is vacating the premises indicated below as of _____. In accordance with our agreement with you, we have connected the Electricity ☐ Gas ☐ service in your name.

_____ Account: _____

_____ Location: _____

_____ MONTANA-DAKOTA UTILITIES CO.

_____ By: _____

WHITE – District Office Copy

YELLOW – Customer Copy

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 13
Canceling Vol. 1 Original Sheet No. 16

GUARANTEE OF PAYMENT FOR NATURAL GAS AND/OR ELECTRIC SERVICE BY A SECOND PARTY IN LIEU OF A DEPOSIT

GUARANTEE OF PAYMENT FOR NATURAL GAS AND/OR
ELECTRIC SERVICE BY A SECOND PARTY IN LIEU OF A DEPOSIT

304SDMD-01
Rev. 9/00

MONTANA-DAKOTA UTILITIES CO.
GUARANTEE OF PAYMENT FOR
NATURAL GAS AND/OR ELECTRIC SERVICE

(Date) _____

To: Montana-Dakota Utilities Co.

(Address) _____

(City, State, Zip Code) _____

For value received, I, _____ (Name of Guarantor), do hereby absolutely guarantee to pay to Montana-Dakota Utilities Co. (Montana-Dakota), upon its request and at the location listed above, the outstanding balance accrued by _____ (Name of Customer) in the event that Customer's bill for natural gas and/or electricity provided by Montana-Dakota at _____ (Customer's Service Address) is not paid when due; however, liability under this Guarantee, other than the collection costs noted below, shall not exceed the sum of $ _____. As Guarantor, I request copies of all disconnect notices sent to the Customer.

Liability under this Guarantee shall begin on _____, 19 ____, and shall continue until Customer has paid for natural gas and/or electric service when due in a prompt and satisfactory manner for twelve consecutive months in accordance with Public Service Commission or Public Utilities Commission rules. I expressly waive receipt of notice of Montana-Dakota's acceptance of my guarantee.

I also agree to pay any and all costs that Montana-Dakota may incur in the collection of this guarantee. In the event legal action is required or becomes necessary to collect the outstanding balance accrued by the Customer from me under this guarantee, I agree to pay all legal fees, including attorneys' fees, in the amount the court determines is reasonable.

I ACKNOWLEDGE THAT I HAVE CAREFULLY READ THE ABOVE GUARANTEE AGREEMENT AND THAT I HAVE RECEIVED A COPY OF IT.

GUARANTOR

_____ (Signature of Witness)

_____ (Signature of Guarantor)

_____ (Guarantor's Mailing Address)

_____ (Guarantor's Street Address—If Different than Mailing Address)

_____ (City, State, Zip Code)

_____ (Guarantor's Telephone Number)

DIVISION OFFICE – White Copy CUSTOMER COPY – Yellow Copy GUARANTOR COPY – Pink Copy

Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.:

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
Original Sheet No. 16

FINAL NOTICE PRIOR TO DISCONNECT

MONTANA-DAKOTA UTILITIES CO

Account Number:

FINAL NOTICE

WE WANT TO CONTINUE OUR DEPENDABLE SERVICE TO YOU,
OUR VALUED CUSTOMER; BUT YOU MUST TAKE ACTION NOW.

Date:

Service Address:

YOUR SERVICE ACCOUNT IS SERIOUSLY PAST DUE.

THIS IS YOUR FINAL NOTIFICATION THAT YOUR GAS AND/OR ELECTRIC SERVICE WILL BE DISCONTINUED IMMEDIATELY -

Unless your past due amount is paid in full or satisfactory arrangements are made in person to the CREDIT DEPARTMENT of MONTANA-DAKOTA UTILITIES CO. by 5:00 p.m. on _____.

If service is disconnected, payment in full and a reconnect fee of _____ to restore service during normal working hours plus a deposit or additional deposit of will be required before service is restored.

PLEASE CONTACT US NOW TO AVOID ANY INCONVENIENCE
THANK YOU.

	PAST DUE	CURRENT	ACCT BALANCE
UTILITY:			
DEPOSIT:	$0.00	$0.00	$0.00

DIRECT INQUIRIES TO:
MONTANA-DAKOTA UTILITIES CO
PO BOX 1060
RAPID CITY SD 57709
1 605 342 0187

DIRECT UNRESOLVED COMPLAINTS TO:
SD PUBLIC UTILITIES COMMISSION
500 E CAPITOL
PIERRE SD 57501
1 800 332 1782

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG04-____
STATEMENTS A – R

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 South Dakota

MONTANA-DAKOTA UTILITIES CO.

Docket No. NG-04-____

Index

Rule	Statement or Schedule	Description
20:10:13:51	A	Balance Sheet
20:10:13:52	B	Income Statement
20:10:13:53	C	Retained Earnings
20:10:13:54	D	Gas Utility Plant in Service
20:10:13:55	D-1	Detailed Cost of Gas Plant
20:10:13:56	D-2	Book Changes in Gas Plant in Service
20:10:13:57	D-3	Average Monthly Gas Plant Balances
20:10:13:58	D-4	Book Changes in Gas Plant in Service – Previous Years
20:10:13:59	D-5	Methods and Procedures Followed in Capitalizing AFUDC and Other Construction Overheads
20:10:13:60	D-6	Significant Changes in Intangible Plant
20:10:13:61	D-7	Working Papers on Plant Not Used and Useful
20:10:13:62	D-8	Description of Property Records
20:10:13:63	D-9	Plant Acquisitions Without Regulatory Approval
20:10:13:64	E	Accumulated Provisions for Depreciation and Amortization
20:10:13:65	E-1	Book Changes in Accumulated Provision for Depreciation and Amortization

MONTANA-DAKOTA UTILITIES CO.

Docket No. NG-04-____

Index

20:10:13:66	E-2	Procedures Followed in Depreciating or Amortizing Plant and Recording Abandonments
20:10:13:67	E-3	Allocation of Overall Accounts to Functional Groups
20:10:13:68	F	Working Capital
20:10:13:69	F-1	Materials and Supplies, Prepayments, and Customer Advances for Construction
20:10:13:70	F-2	Materials and Supplies – Previous Years
20:10:13:71	F-3	Customer Advances for Construction
20:10:13:72	G	Gas Utility Cost of Capital
20:10:13:73		Adjusted Embedded Long-Term Debt Costs
20:10:13:74		Adjusted Embedded Preferred Stock Cost
20:10:13:75		Common Stock
20:10:13:76	G-1	Stock Dividends, Stock Splits or Changes in Par or Stated Value
20:10:13:77	G-2	Common Stock Data – Five Years
20:10:13:78	G-3	Reacquisition of Bonds or Preferred Stock – 18 Months
20:10:13:80	H	Operation and Maintenance Expenses
20:10:13:81	H-1	Adjustments to Operation and Maintenance Expenses
20:10:13:82	H-2	Cost of Gas
20:10:13:83	H-3	Listed Expense Accounts
20:10:13:84	H-4	Intercompany Transactions

MONTANA-DAKOTA UTILITIES CO.

Docket No. NG-04-____

Index

20:10:13:85	I	Operating Revenues
20:10:13:86	J	Depreciation and Amortization Expenses
20:10:13:87	J-1	Depreciation Expense Charged to Other Than Prescribed Depreciation and Expense Amortization
20:10:13:88	K	Income Taxes
20:10:13:89	K-1	Reconciliation of Net Income Per Books with Taxable Income Per Federal Income Tax Return
20:10:13:90	K-2	Tax Depreciation Deductions
20:10:13:91	K-3	Consolidated Federal Income Tax
20:10:13:92	K-4	Allowance for Current Tax in Excess of Tax Calculated at Consolidated Tax Rate
20:10:13:93	K-5	Claimed Allowance for State Income Taxes
20:10:13:94	L	Taxes Other Than Income Tax
20:10:13:95	L-1	Adjustments to Taxes Other Than Income Tax
20:10:13:96	M	Overall Cost of Service
20:10:13:97	N	Allocated Cost of Service
20:10:13:98	O	Class Cost of Service Study
20:10:13:99	O-1	Derivation of Increased Rates
20:10:13:100	P	Gas Cost Adjustment Factor
20:10:13:101	Q	Description of Utility Operations
20:10:13:102	R	Intercompany Transactions

DOCKET NO.___
RULE 20:10:13:51
STATEMENT A

INDEX

Balance Sheet	Page Nos.
Twelve months ended December 31, 2002 and 2003	1 - 2
Twelve months ended March 31, 2003 and 2004	3 - 4
Notes to the Financial Statements	

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2002 AND
DECEMBER 31, 2003

	2002	2003
Assets and Other Debits		
Utility Plant	$845,518,266	$881,126,491
Construction Work in Progress	18,641,586	11,357,572
Less Acc. Provision for Depreciation and Amortization	496,483,634	512,484,759
Net Utility Plant	367,676,218	379,999,304
Gas Stored Underground - Noncurrent	1,913,520	2,361,258
Other Property and Investments		
Nonutility Property	174,544	1,036,084
(Less) Accum. Prov. for Depr. And Amort.	79,695	353,568
Investment in Subsidiary Companies	1,130,703,822	1,278,850,163
Other investments	26,757,835	22,254,889
Net Other Property and Investments	1,157,556,506	1,301,787,568
Current and Accrued Assets		
Cash	5,959,888	861,378
Special Deposits	1,200	1,200
Working Fund	130,965	15,965
Temporary Cash Investments	3,297,879	8,529,412
Customer Accounts Receivable	28,398,322	37,004,255
Other Accounts Receivable	2,365,820	3,987,038
(Less) Accum.Prov. For Uncollectible Acct. - Credit	241,038	319,419
Accounts Receivable from Assoc.Companies	16,147,799	17,473,063
Fuel Stock	2,233,437	2,753,765
Plant Materials and Operating Supplies	5,894,011	6,197,652
Merchandise	1,012,624	1,139,740
Gas Stored Underground - Current	15,322,047	18,438,454
Prepayments	7,220,656	8,839,446
Interest and Dividends Receivable		
Accured Utility Revenues	20,628,893	27,625,923
Miscellaneous Current and Accrued Assets	57,814	117,438
Total Current and Accrued Assets	108,430,317	132,665,310
Deferred Debits		
Unamortized Debt Expenses	1,123,696	1,533,592
Other Regulatory Assets	3,651,680	4,744,491
Prelim. Survey and Investigation Charges (Electric)	1,686,727	1,127,322
Clearing Accounts	(40,451)	(124,215)
Miscellaneous Deferred Debits	19,360,006	22,910,284
Unamortized Loss on Reaquired Debt	5,627,511	4,518,768
Accumulated Deferred Income Taxes	20,176,715	21,238,378
Unrecovered Purchased Gas Costs	(2,396,235)	10,518,527
Total Deferred Debits	49,189,649	66,467,147
Total Assets and Other Debits	$1,684,766,210	$1,883,280,587

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2002 AND
DECEMBER 31, 2003

	2002	2003
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$74,282,038	$113,716,632
Preferred Stock Issued	16,300,000	16,200,000
Premium on Capital Stock	751,331,277	761,023,634
(Less) Capital Stock Expense	3,236,160	3,236,160
Retained Earnings	44,231,211	47,203,550
Unappropriated Undistributed Sub Earnings	430,566,718	528,082,638
Accumulated Other Comprehensive Income	(9,803,865)	(7,528,653)
Total Proprietary Capital	1,303,671,219	1,455,461,641
Long-Term Debt		
Bonds	130,850,000	160,850,000
Other Long-Term Debt	52,000,000	41,500,000
(Less) Unamortized Discount on Long-Term Debt-Debit	41,116	36,671
Total Long-Term Debt	182,808,884	202,313,329
Other Noncurrent Liabilities		
Accumulated Provision for Injuiries and Damages	1,415,463	1,017,175
Accumulated Provision for Pensions and Benefits	24,086,968	29,785,661
Accumulated Provision for Rate Refunds	67,067	299,228
Asset Retirement Obligations	0	602,589
Total Other Noncurrent Liabilities	25,569,498	31,704,653
Current and Accrued Liabilities		
Notes Payable	8,000,000	0
Accounts Payable	18,828,269	26,572,779
Accounts Payable to Associated Companies	5,882,199	7,113,407
Customer Deposits	1,472,979	1,584,497
Taxed Accrued	(464,747)	10,323,491
Interest Accrued	2,212,959	2,307,669
Dividends Declared	17,959,379	19,458,320
Tax Collections Payable	1,210,339	1,662,094
Miscellaneous Current and Accrued Liabilities	10,489,414	10,665,144
Total Current and Accrued Assets	65,590,791	79,687,401
Deferred Debits		
Customer Advances for Construction	1,533,151	1,284,167
Accumulated Deferred Investment Tax Credit	3,058,287	2,461,954
Other Deferred Credits	14,584,248	16,816,218
Other Regulatory Liabilities	15,563,924	15,633,652
Accumulated Deferred Income Taxes	72,386,208	77,917,572
Total Deferred Credits	107,125,818	114,113,563
Total Liabilities and Equity	$1,684,766,210	$1,883,280,587

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
MARCH 31, 2003 AND
MARCH 31, 2004

	2003	2004
Assets and Other Debits		
Utility Plant	$849,833,913	$882,330,354
Construction Work in Progress	27,055,714	11,493,507
Less Acc. Provision for Depreciation and Amortization	501,626,030	516,007,380
Net Utility Plant	375,263,597	377,816,481
Gas Stored Underground - Noncurrent	1,725,800	2,361,258
Other Property and Investments		
Nonutility Property	142,601	1,102,860
(Less) Accum. Prov. for Depr. And Amort.	50,783	388,801
Investment in Subsidiary Companies	1,125,503,905	1,337,219,393
Other investments	26,670,769	30,679,344
Net Other Property and Investments	1,152,266,492	1,368,612,796
Current and Accrued Assets		
Cash	4,204,256	4,388,382
Special Deposits	1,200	1,200
Working Fund	15,967	15,965
Temporary Cash Investments	5,446,336	12,624,829
Customer Accounts Receivable	46,425,292	43,636,578
Other Accounts Receivable	2,977,617	3,771,698
(Less) Accum.Prov. For Uncollectible Acct. - Credit	462,854	560,546
Accounts Receivable from Assoc.Companies	16,953,001	19,404,258
Fuel Stock	2,186,954	2,296,690
Plant Materials and Operating Supplies	6,195,382	6,306,289
Merchandise	1,012,558	1,076,790
Stores Expense Undistributed	8,743	3,120
Gas Stored Underground - Current	36,333	1,084,742
Prepayments	4,107,599	5,064,135
Accured Utility Revenues	21,122,498	19,605,726
Miscellaneous Current and Accrued Assets	5,166	33,898
Total Current and Accrued Assets	110,236,048	118,753,754
Deferred Debits		
Unamortized Debt Expenses	1,090,378	1,576,063
Other Regulatory Assets	4,259,819	3,742,350
Prelim. Survey and Investigation Charges (Electric)	789,226	871,500
Clearing Accounts	342,997	314,334
Miscellaneous Deferred Debits	19,841,244	23,210,948
Unamortized Loss on Reaquired Debt	5,350,326	4,264,842
Accumulated Deferred Income Taxes	23,159,044	24,630,226
Unrecovered Purchased Gas Costs	(138,357)	10,890,575
Total Deferred Debits	54,694,677	69,500,838
Total Assets and Other Debits	$1,694,186,614	$1,937,045,127

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
MARCH 31, 2003 AND
MARCH 31, 2004

	2003	2004
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$74,337,088	$117,151,449
Preferred Stock Issued	16,300,000	15,000,000
Premium on Capital Stock	753,479,760	835,076,666
(Less) Capital Stock Expense	3,236,160	3,399,279
(Less) Reacquired Capital Stock	0	744,337
Retained Earnings	48,921,353	48,332,047
Unappropriated Undistributed Sub Earnings	428,013,882	530,454,563
Accumulated Other Comprehensive Income	(14,502,066)	(13,541,681)
Total Proprietary Capital	1,303,313,857	1,528,329,428
Long-Term Debt		
Bonds	130,850,000	160,850,000
Other Long-Term Debt	41,500,000	1,200,000
(Less) Unamortized Discount on Long-Term Debt-Debit	40,005	35,560
Total Long-Term Debt	172,309,995	162,014,440
Other Noncurrent Liabilities		
Accumulated Provision for Injuiries and Damages	1,617,096	1,266,560
Accumulated Provision for Pensions and Benefits	24,178,972	30,157,130
Accumulated Provision for Rate Refunds	325,441	0
Asset Retirement Obligations	571,856	613,196
Total Other Noncurrent Liabilities	26,693,365	32,036,886
Current and Accrued Liabilities		
Notes Payable	0	0
Accounts Payable	19,314,814	23,006,849
Accounts Payable to Associated Companies	6,487,942	7,460,720
Customer Deposits	1,459,908	1,599,134
Taxed Accrued	8,919,151	10,730,264
Interest Accrued	4,656,240	5,188,401
Dividends Declared	17,971,180	20,024,269
Tax Collections Payable	1,759,123	1,926,813
Miscellaneous Current and Accrued Liabilities	22,924,886	28,186,849
Total Current and Accrued Assets	83,493,244	98,123,299
Deferred Debits		
Customer Advances for Construction	1,334,730	1,288,749
Accumulated Deferred Investment Tax Credit	2,909,898	2,320,045
Other Deferred Credits	15,235,160	19,393,617
Other Regulatory Liabilities	15,607,823	15,198,421
Accumulated Deferred Income Taxes	73,288,542	78,340,242
Total Deferred Credits	108,376,153	116,541,074
Total Liabilities and Equity	$1,694,186,614	$1,937,045,127

Docket No. ____
Rule 20:10:13:5
STATEMENT A

NOTES TO THE FINANCIAL STATEMENTS

NOTE 1
Summary of Significant Accounting Policies
Basis of presentation
The consolidated financial statements of MDU Resources Group, Inc. and its subsidiaries (Company) include the accounts of the following businesses: electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, construction materials and mining, and independent power production and other The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Utility services, natural gas and oil production, construction materials and mining, and independent power production and other are nonregulated. For further descriptions of the Company's businesses, see Note 14. The statements also include the ownership interests in the assets, liabilities and expenses c two jointly owned electric generation stations.

The Company uses the equity method of accounting for certain investments including its 49 percent interest in MPX Participacoes, Ltda. (MPX), which was formed to develop electric generation and transmission, steam generation, power equipment and coal mining projects i Brazil. For more information on the Company's equity investments, see new accounting standards in Note 1, as well as Note 2.

The Company's regulated businesses are subject to various state and federal agency regulation. The accounting policies followed by these businesses are generally subject t the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Regulation." SFAS No. 71 requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense c income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and th applicable state public service commissions. See Note 4 for more information regarding the nature and amounts of these regulatory deferrals.

Prior to the sale of the Company's coal operations in 2001, as discussed in Note 14, intercompany coal sales, which were made at prices approximately the same as those charge to others, and the related utility fuel purchases were not eliminated in accordance with the provisions of SFAS No. 71. All other significant intercompany balances and transactions have been eliminated in consolidation.

Cash and cash equivalents
The Company considers all highly liquid investments purchased with an original maturity c three months or less to be cash equivalents.

Allowance for doubtful accounts
The Company's allowance for doubtful accounts as of December 31, 2003 and 2002, was $8.1 million and $8.2 million, respectively.

Natural gas in underground storage
Natural gas in underground storage for the Company's regulated operations is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year was included in inventories and amounted to $19.6 million at December 31, 2003, and $18.2 million at December 31, 2002. The remainder of natural gas in underground storage was included in other assets and was $42.6 million at December 31, 2003, and $42.2 million at December 31, 2002.

Inventories
Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $54.7 million and $39.6 million, materials and supplies of $27.2 million and $23.0 million, and other inventories of $12.6 million and $12.3 million, as of December 31, 2003 and 2002, respectively. These inventories were stated at the lower of average cost or market.

Property, plant and equipment
Additions to property, plant and equipment are recorded at cost when first placed in service. Acquired aggregate reserves at the Company's construction materials and mining business are classified based on type of ownership. Owned mineral rights are classified as property, plant and equipment, whereas leased mineral rights are classified as other intangible assets, net. For more information on other intangible assets, net, see Note 3. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described in natural gas and oil properties in Note 1, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize an allowance for funds used during construction (AFUDC) on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $7.4 million, $7.6 million and $6.6 million in 2003, 2002 and 2001, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable reserves, which are depleted based on the units-of-production method based on recoverable deposits, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves.

Property, plant and equipment at December 31, 2003 and 2002, was as follows:

	2003	2002	Estimated Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	$ 639,893	$ 619,230	4-50
Natural gas distribution:			
Natural gas distribution plant	252,591	244,930	4-40
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities	340,841	262,971	3-70
Nonregulated:			
Utility services:			
Land	2,505	2,601	---
Buildings and improvements	10,123	8,768	10-40
Machinery, vehicles and equipment	58,843	54,833	2-10
Other	5,400	4,458	3-10
Pipeline and energy services:			
Natural gas gathering and other facilities	119,613	108,179	3-20
Energy services	1,339	1,270	3-15
Natural gas and oil production:			
Natural gas and oil properties	862,839	748,843	(a)
Other	8,518	6,945	5-7
Construction materials and mining:			

Land	89,545	85,376	---
Buildings and improvements	48,907	43,144	1-40
Machinery, vehicles and equipment	569,295	493,349	1-25
Construction in progress	14,392	10,151	---
Depletable reserves	171,841	172,235	(b)
Independent power production and other:			
Electric generation	153,947	58,000	5-30
Construction in progress	29,805	19,342	---
Land	2,001	2,001	---
Other	15,381	15,182	3-20
Less accumulated depreciation, depletion and amortization	1,175,326	1,019,438	
Net property, plant and equipment	$ 2,222,293	$ 1,942,370	

(a) Amortized on the units-of-production method based on total proved reserves at an Mc equivalent rate of $.89, $.80, and $.78 for the years ended December 31, 2003, 200: and 2001, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $104,339 and $145,692 were excluded from amortization at December 31, 2003 and 2002, respectively.

(b) Depleted based on the units-of-production method based on recoverable deposits.

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairmer recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No long-lived assets have been impaired and, accordingly, no impairment losses have been recorded in 2003, 2002 and 200: Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. On January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangibles," and ceased amortization of its goodwill. Goodwill is required to be tested for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. In accordance with SFAS No. 142, the Company performed its transitional goodwill impairment testing as of January 1, 2002, and performed its annual goodwill impairment testing as of October 31, 2003 and 2002, and determined that no impairments existed at those dates. Therefore, no impairment loss has been recorded for the years ended December 31, 2003 and 2002. For more information on goodwill, see Note 3.

Natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil productic activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties including gains or losses on abandonments of properties, are treated as adjustments to th cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves based on single point-in-time spot market prices, as mandated under the rules of the Securities and Exchange Commission, and the lower of cost or fair value of unproved properties. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash

write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

At December 31, 2003 and 2002, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2003, could result in a future write-down of the Company's natural gas and oil properties.

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2003, in total and by year in which such costs were incurred:

		Year Costs Incurred			
	Total	2003	2002	2001	2000 and prior
			(In thousands)		
Acquisition	$ 48,355	$ 630	$ 17,108	$---	$30,617
Development	39,160	28,351	5,120	---	5,689
Exploration	4,885	4,828	---	23	34
Capitalized interest	11,939	5,642	6,297	---	---
Total costs not subject to amortization	$104,339	$ 39,451	$ 28,525	$ 23	$ 36,340

Costs not subject to amortization as of December 31, 2003, consisted primarily of lease acquisition costs, unevaluated drilling costs and capitalized interest associated with coalbed development in the Powder River Basin of Montana and Wyoming. The Company expects that the majority of these costs will be evaluated over the next three- to five-year period and included in the amortization base as the properties are developed and evaluated and proved reserves are established or impairment is determined.

Revenue recognition
Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is probable. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from natural gas and oil production activities only on that portion of production sold and allocable to the Company's ownership interest in the related well. Revenues at the independent power production operations are recognized based on electricity delivered and capacity provided, pursuant to contractual commitments. The Company recognizes all other revenues when services are rendered or goods are delivered.

Percentage-of-completion method
The Company recognizes construction contract revenue from fixed price and modified fixed price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. Costs in excess of billings on uncompleted contracts of $31.8 million and $19.4 million for the years ended December 31, 2003 and 2002, respectively, represents revenues recognized in excess of amounts billed and was included in receivables, net. Billings in excess of costs on uncompleted contracts of $20.4 million and $24.5 million for the years ended December 31, 2003 and 2002, respectively, represents billings in excess of revenues recognized and was included in accounts payable. Also included in receivables, net were amounts representing balances billed but not paid by customers under retainage provisions in contracts that amounted to $34.3 million and $25.6 million as of December 31, 2003 and 2002, respectively, which are expected to be paid within one year or less.

Derivative instruments
The Company's policy allows the use of derivative instruments as part of an overall energ price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions and the Company has procedures in place to monitor complianc with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties. The Company's policy requires settlement of natural gas and oil price derivative instruments monthly ar all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may nc exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings and credit exposure limitations. Accordingly, the Company does not anticipate any material effect to its financial positic or results of operations as a result of nonperformance by counterparties.

Advertising
The Company expenses advertising costs as incurred and the amount of advertising expense for the years 2003, 2002 and 2001, was $3.9 million, $3.4 million and $2.9 million, respectively.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundabl through rate adjustments within a period ranging from 24 months to 28 months from the tir such costs are paid. Natural gas costs recoverable through rate adjustments amounted to $10.5 million at December 31, 2003, which is included in prepayments and other current assets. Natural gas costs refundable through rate adjustments amounted to $2.4 million a December 31, 2002, which is included in other accrued liabilities.

Insurance
Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $500,000 per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $500,000 per accident or occurrence. These subsidiaries have excess coverage on a claims first-made basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up t the deductible amounts accrued on the basis of estimates of liability for claims incurre and claims incurred but not reported.

Other income - net
Other income - net consisted of the following:

Years ended December 31,	2003	2002 (In thousands)	2001
Interest and dividend income	$ 6,722	$ 8,160	$ 5,734
Earnings from equity method investments (Note 2)	5,968	1,341	154
Other income	9,517	4,071	20,933
Total other income - net	$22,207	$13,572	$26,821

Income taxes
The Company provides deferred federal and state income taxes on all temporary difference between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities resulting fr the Company's adoption of SFAS No. 109, "Accounting for Income Taxes," have been recorde as a regulatory liability and are included in other liabilities. These regulatory

liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Foreign currency translation adjustment
The functional currency of the Company's investment in a 220-megawatt natural gas-fired electric generating facility in Brazil, as further discussed in Note 2, is the Brazilian real. Translation from the Brazilian real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses have been translated using the weighted average exchange rate for each month prevailing during the period reported. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity are recorded in income.

Common stock split
On August 14, 2003, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 11.

Earnings per common share
Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. For the years ended December 31, 2003, 2002 and 2001, 209,805 shares, 3,674,925 shares and 225,945 shares, respectively, with an average exercise price of $24.56, $20.08 and $24.57, respectively, attributable to the exercise of outstanding options, were excluded from the calculation of diluted earnings per share because their effect was antidilutive. For the years ended December 31, 2003, 2002 and 2001, no adjustments were made to reported earnings in the computation of earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation
The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. Compensation expense recognized for awards granted on or after January 1, 2003, for the year ended December 31, 2003, was $41,000 (after tax).

As permitted by SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of SFAS No. 123," the Company accounts for stock options granted prior to January 1, 2003, under APB Opinion No. 25, "Accounting for Stock Issued to Employees." No compensation expense has been recognized for stock options granted prior to January 1, 2003, as the options granted had an exercise price equal to the market value of the underlying common stock on the date of the grant.

Since the Company adopted SFAS No. 123 effective January 1, 2003, for newly granted options only, the following table illustrates the effect on earnings and earnings per common share for the years ended December 31, 2003, 2002 and 2001, as if the Company had applied SFAS No. 123 and recognized compensation expense for all outstanding and unvested

stock options based on the fair value at the date of grant:

	2003	2002	2001
	(In thousands, except per share amounts)		
Earnings on common stock, as reported	$ 174,607	$ 147,688	$ 155,087
Stock-based compensation expense included in reported earnings, net of related tax effects	41	---	---
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects	(2,139)	(2,862)	(3,799)
Pro forma earnings on common stock	$ 172,509	$ 144,826	$ 151,288
Earnings per common share -- basic -- as reported:			
Earnings before cumulative effect of accounting change	$ 1.64	$ 1.39	$ 1.54
Cumulative effect of accounting change	(.07)	---	---
Earnings per common share -- basic	$ 1.57	$ 1.39	$ 1.54
Earnings per common share -- basic -- pro forma:			
Earnings before cumulative effect of accounting change	$ 1.62	$ 1.36	$ 1.50
Cumulative effect of accounting change	(.07)	---	---
Earnings per common share -- basic	$ 1.55	$ 1.36	$ 1.50
Earnings per common share -- diluted -- as reported:			
Earnings before cumulative effect of accounting change	$ 1.62	$ 1.38	$ 1.52
Cumulative effect of accounting change	(.07)	---	---
Earnings per common share -- diluted	$ 1.55	$ 1.38	$ 1.52
Earnings per common share -- diluted -- pro forma:			
Earnings before cumulative effect of accounting change	$ 1.60	$ 1.36	$ 1.49
Cumulative effect of accounting change	(.07)	---	---
Earnings per common share -- diluted	$ 1.53	$ 1.36	$ 1.49

For more information on the Company's stock-based compensation, see Note 12.

Use of estimates
The preparation of financial statements in conformity with accounting principles general accepted in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the report amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil reserves; property depreciable lives; tax provisions;

uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments, including the fair value of an embedded derivative in a power purchase agreement related to an equity method investment in Brazil, as discussed in Note 2. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information
Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2003	2002	2001
		(In thousands)	
Interest, net of amount capitalized	$47,474	$37,788	$42,267
Income taxes	$31,737	$60,988	$75,284

Reclassifications
The Consolidated Statements of Income have been reclassified to include additional disclosures relating to the components comprising operating revenues and operation and maintenance expense.

Certain other reclassifications have been made in the financial statements for prior years to conform to the current presentation. Such reclassifications had no effect on net income or stockholders' equity as previously reported.

New accounting standards
The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. For a discussion of the effect of the adoption of the fair value recognition provisions of SFAS No. 123 on earnings and earnings per share, see stock-based compensation in Note 1.

In June 2001, the Financial Accounting Standards Board (FASB) approved SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for the recorded amount or incurs a gain or loss. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. For more information on the adoption of SFAS No. 143, see Note 9.

In April 2002, the FASB approved SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections." FASB No. 4 required all gains or losses from extinguishment of debt to be classified as extraordinary items net of income taxes. SFAS No. 145 requires that gains and losses from extinguishment of debt be evaluated under the provisions of APB Opinion No. 30, and be classified as ordinary items unless they are unusual or infrequent or meet the specific criteria for treatment as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. The adoption of SFAS No. 145 did not have a material effect on the Company's financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 clarifies the disclosures to be made by a guarantor in its

interim and annual financial statements about its obligations under certain guarantees that it has issued. FIN 45 also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing certain types of guarantees. Certain types of guarantees are not subject to the initial recognition and measurement provisions of FIN 45 but are subject to its disclosure requirements. The initial recognition and initial measurement provisions of FIN 45 are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, regardless of the guarantor's fiscal year-end. The guarantor's previous accounting for guarantees issued prior to the date of the initial application of FIN 45 is not required to be revised or restated. The disclosure requirements in FIN 45 are effective for financial statements of interim or annual periods ended after December 15, 2002. The Company is applying the initial recognition and initial measurement provisions of FIN 45 to guarantees issued or modified after December 31, 2002. For more information on the Company's guarantees and the disclosure requirements of FIN 45, as applicable to the Company, see Note 19.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 provides clarification on the financia accounting and reporting of derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities; and requires contracts with similar characteristics to be accounted for on a comparable basis. SFAS No. 149 is generally effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The adoption of SFAS No. 149 did not have a material effect on the Company's financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within the scope of SFAS No. 150 as a liability (or an asset in some circumstances). SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The Company will apply SFAS No. 150 to any financial instruments entered into or modified after May 31, 2003. Beginning in 2003, th Company reported its preferred stock subject to mandatory redemption as a liability in accordance with SFAS No. 150. The transition to SFAS No. 150 did not have a material effect on the Company's financial position or results of operations.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised 2003), "Consolidation of Variable Interest Entities" (FIN 46 (revised)), which revised FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 (revised) clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated support. A enterprise shall consolidate a variable interest entity if that enterprise is the primary beneficiary. An enterprise is considered the primary beneficiary if it has a variable interest that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns or both.

FIN 46 (revised) shall be applied to all entities subject to FIN 46 (revised) no later than the end of the first reporting period that ends after March 15, 2004. However, an entity that applied FIN 46 to an entity prior to the effective date of FIN 46 (revised) shall either continue to apply FIN 46 until the effective date of FIN 46 (revised) or apply FIN 46 (revised) at an earlier date.

The Company had evaluated the provisions of FIN 46 and determined that MPX is a variable interest entity. MPX was formed in August 2001, as a result of MDU Brasil Ltda. (MDU Brasil), an indirect wholly owned Brazilian subsidiary of the Company, entering into a

joint venture agreement with a Brazilian firm. MDU Brasil has a 49 percent interest in MPX. Although the Company has determined that MPX is a variable interest entity, MDU Brasil is not considered the primary beneficiary of MPX because MDU Brasil does not absorb a majority of MPX's expected losses, receive a majority of MPX's expected residual returns or both. Therefore, MDU Brasil does not have a controlling financial interest in MPX and is not required to consolidate MPX in its financial statements. MPX is being accounted for under the equity method of accounting. For more information on this equity method investment, see Note 2. The adoption of FIN 46 did not have an effect on the Company's financial position or results of operations. The Company will continue to apply FIN 46 until the effective date of FIN 46 (revised).

In December 2003, the FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pension and Other Postretirement Benefits." SFAS No. 132 (revised 2003) retains the disclosure requirements contained in SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other postretirement benefit plans. SFAS No. 132 (revised 2003) is effective for financial statements with fiscal years ending after December 15, 2003. The interim-period disclosures required by SFAS No. 132 (revised 2003) are effective for interim periods beginning after December 15, 2003. The Company applied SFAS No. 132 (revised 2003) to its consolidated financial statements issued after December 15, 2003. For more information on the Company's pension and other postretirement benefits, see Note 16.

In January 2004, the FASB issued FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FASB Staff Position No. FAS 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (2003 Medicare Act). SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pension," requires enacted changes in relevant laws to be considered in current period measurements of postretirement benefit costs and accumulated postretirement benefit obligation. The Company provides prescription drug benefits to certain eligible employees and has elected the one-time deferral of accounting for the effects of the 2003 Medicare Act. These consolidated financial statements and accompanying notes do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plans. The Company intends to analyze the 2003 Medicare Act, along with the authoritative guidance, when issued, to determine if its benefit plans need to be amended and how to record the effects of the 2003 Medicare Act. Specific guidance on the accounting for the federal subsidy provided by the 2003 Medicare Act is pending and that guidance, when issued, could require the Company to change previously reported postretirement benefit information. For more information on the Company's postretirement benefits, see Note 16.

Comprehensive income

Comprehensive income is the sum of net income as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains and losses on derivative instruments qualifying as hedges, minimum pension liability adjustments and foreign currency translation adjustments.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2003, 2002 and 2001, were as follows:

	2003	2002	2001
		(In thousands)	
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Unrealized loss on derivative			

instruments at January 1, 2001, due to cumulative effect of a change in accounting principle, net of tax of $3,970 in 2001	$ ---	$ ---	$(6,080)
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $2,132, $2,903 and $1,448 in 2003, 2002 and 2001, respectively	(3,335)	(4,541)	2,218
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $2,903, $1,448 and $3,970 in 2003, 2002 and 2001, respectively	(4,541)	2,218	(6,080)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	1,206	(6,759)	2,218
Minimum pension liability adjustment, net of tax of $38 and $2,876 in 2003 and 2002, respectively	21	(4,464)	---
Foreign currency translation adjustment	1,048	(799)	---
Total other comprehensive income (loss)	$ 2,275	$(12,022)	$ 2,218

The after-tax components of accumulated other comprehensive income (loss) as of December 31, 2003, 2002 and 2001, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Minimum Pension Liability Adjustment	Foreign Currency Translation Adjustment	Total Accumulated Other Comprehensive Income (Loss)
		(In thousands)		
Balance at December 31, 2001	$ 2,218	$ ---	$ ---	$ 2,218
Balance at December 31, 2002	$ (4,541)	$ (4,464)	$ (799)	$ (9,804)
Balance at December 31, 2003	$ (3,335)	$ (4,443)	$ 249	$ (7,529)

NOTE 2
Equity Method Investments
The Company has a number of equity method investments, including MPX, which was formed i August 2001 when MDU Brasil entered into a joint venture agreement with a Brazilian firm MDU Brasil has a 49 percent interest in MPX, which is being accounted for under the equi method of accounting, as discussed in Note 1. MPX, through a wholly owned subsidiary, owns a 220-megawatt natural gas-fired electric generating facility (Brazil Generating Facility) in the Brazilian state of Ceara. At December 31, 2003, MPX has assets of approximately $109.6 million and long-term debt of approximately $86.8 million, includin a loan of $20.0 million from Centennial Energy Resources International Inc, an indirect wholly owned subsidiary of the Company. Petrobras, the Brazilian state-controlled energ company, has agreed to purchase all of the capacity and market all of the Brazil Generating Facility's energy. The power purchase agreement with Petrobras expires in Ma 2008. Petrobras also is under contract to supply natural gas to the Brazil Generating Facility during the term of the power purchase agreement. This natural gas supply

contract is renewable by a wholly owned subsidiary of MPX for an additional 13 years. The functional currency for the Brazil Generating Facility is the Brazilian real. The power purchase agreement with Petrobras contains an embedded derivative, which derives its value from an annual adjustment factor, which largely indexes the contract capacity payments to the U.S. dollar. For the year ended December 31, 2003, the Company's 49 percent share of the loss from the change in the fair value of the embedded derivative in the power purchase agreement was $11.3 million (after tax). For the year ended December 31, 2002, the Company's 49 percent share of the gain from the change in the fair value of the embedded derivative in the power purchase agreement was $13.6 million (after tax). The Company's 49 percent share of the foreign currency gain resulting from the revaluation of the Brazilian real was $2.8 million (after tax) for the year ended December 31, 2003. The Company's 49 percent share of the foreign currency loss resulting from devaluation of the Brazilian real was $9.4 million (after tax) for the year ended December 31, 2002. The Company's investment in the Brazil Generating Facility was approximately $25.2 million, including undistributed earnings of $4.6 million at December 31, 2003. The Company's investment in the Brazil Generating Facility was approximately $27.8 million at December 31, 2002.

The Company's share of income from its equity method investments, including MPX, was $6.0 million, $1.3 million and $154,000 for the years ended December 31, 2003, 2002 and 2001, respectively, and was included in other income - net.

NOTE 3
Goodwill and Other Intangible Assets
On January 1, 2002, in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," the Company ceased amortization of its goodwill recorded in business combinations that occurred on or before June 30, 2001. The following information is presented as if SFAS No. 142 was adopted as of January 1, 2001. The reconciliation of previously reported earnings and earnings per common share to the amounts adjusted for the exclusion of goodwill amortization, net of the related income tax effects, for the years ended December 31, 2003, 2002 and 2001, were as follows:

	2003	2002	2001
	(In thousands, except per share amounts)		
Reported earnings on common stock	$ 174,607	$ 147,688	$ 155,087
Add: Goodwill amortization, net of tax	---	---	3,649
Adjusted earnings on common stock	$ 174,607	$ 147,688	$ 158,736
Reported earnings per common share -- basic	$ 1.57	$ 1.39	$ 1.54
Add: Goodwill amortization, net of tax	---	---	.03
Adjusted earnings per common share -- basic	$ 1.57	$ 1.39	$ 1.57
Reported earnings per common share -- diluted	$ 1.55	$ 1.38	$ 1.52
Add: Goodwill amortization, net of tax	---	---	.04
Adjusted earnings per common share -- diluted	$ 1.55	$ 1.38	$ 1.56

The changes in the carrying amount of goodwill for the year ended December 31, 2003, were as follows:

	Balance as of January 1, 2003	Goodwill Acquired During the Year	Balance as of December 31, 2003
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---

Utility services	62,487	117	62,604
Pipeline and energy services	9,494	---	9,494
Natural gas and oil production	---	---	---
Construction materials and mining	111,887	8,311	120,198
Independent power production and other	7,131	---	7,131
Total	$190,999	$8,428	$199,427

The changes in the carrying amount of goodwill for the year ended December 31, 2002, were as follows:

	Balance as of January 1, 2002	Goodwill Acquired During the Year	Balance as of December 31, 2002
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	61,909	578	62,487
Pipeline and energy services	9,336	158	9,494
Natural gas and oil production	---	---	---
Construction materials and mining	102,752	9,135	111,887
Independent power production and other	---	7,131	7,131
Total	$173,997	$17,002	$190,999

Other intangible assets at December 31, 2003 and 2002, were as follows:

	2003	2002
	(In thousands)	
Amortizable intangible assets:		
Leasehold rights	$ 186,419	$ 172,496
Accumulated amortization	(11,779)	(7,494)
	174,640	165,002
Noncompete agreements	12,075	12,075
Accumulated amortization	(9,690)	(9,366)
	2,385	2,709
Other	17,734	7,224
Accumulated amortization	(2,265)	(374)
	15,469	6,850
Unamortizable intangible assets	960	1,603
Total	$ 193,454	$ 176,164

Acquired aggregate reserves at our construction materials and mining business are classified based on type of ownership. Owned mineral rights are classified as property, plant and equipment, whereas leased mineral rights are classified as leasehold rights in other intangible assets, net.

The unamortizable intangible assets were recognized in accordance with SFAS No. 87, "Employers' Accounting for Pensions," which requires that if an additional minimum liability is recognized an equal amount shall be recognized as an intangible asset,

provided that the asset recognized shall not exceed the amount of unrecognized prior service cost. The unamortizable intangible asset will be eliminated or adjusted as necessary upon a new determination of the amount of additional liability.

Amortization expense for amortizable intangible assets for the years ended December 31, 2003 and 2002, was $5.9 million and $3.4 million, respectively. Estimated amortization expense for amortizable intangible assets is $6.2 million in 2004, $6.4 million in 2005, $5.2 million in 2006, $5.2 million in 2007, $5.2 million in 2008 and $164.3 million thereafter.

SFAS No. 142 discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. SFAS No. 141, "Business Combinations," and SFAS No. 142 clarify that more assets should be distinguished and classified between tangible and intangible. The Company did not change or reclassify contractual mineral rights included in property, plant and equipment related to its natural gas and oil production business upon adoption of SFAS No. 142. The Company has included such mineral rights as part of property, plant and equipment under the full-cost method of accounting for natural gas and oil properties. An issue has arisen within the natural gas and oil industry as to whether contractual mineral rights under SFAS No. 142 should be classified as intangible rather than as part of property, plant and equipment. This accounting matter is anticipated to be addressed by the FASB's Emerging Issues Task Force. The resolution of this matter may result in certain reclassifications of amounts in the Consolidated Balance Sheets, as well as changes to Notes to Consolidated Financial Statements in the future. The applicable provisions of SFAS No. 141 and SFAS No. 142 only affect the balance sheet and associated footnote disclosure, so any reclassifications that might be required in the future will not affect the Company's cash flows or results of operations. The Company believes that the resolution of this matter will not have a material effect on the Company's financial position because the mineral rights acquired by its natural gas and oil production business after the June 30, 2001, effective date of SFAS No. 142 were not material.

NOTE 4
Regulatory Assets and Liabilities
The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	2003	2002
	(In thousands)	
Regulatory assets:		
Deferred income taxes	$ 29,850	$ 27,378
Natural gas costs recoverable through rate adjustments	10,519	---
Long-term debt refinancing costs	4,519	5,627
Plant costs	2,697	2,330
Postretirement benefit costs	562	616
Other	7,159	4,788
Total regulatory assets	55,306	40,739
Regulatory liabilities:		
Plant removal and decommissioning costs	76,176	68,551
Reserves for regulatory matters	11,970	9,856
Taxes refundable to customers	11,751	11,699
Deferred income taxes	10,663	5,491
Natural gas costs refundable through rate adjustments	---	2,396
Other	658	2,779
Total regulatory liabilities	111,218	100,772
Net regulatory position	$ (55,912)	$ (60,033)

As of December 31, 2003, substantially all of the Company's regulatory assets, other than certain deferred income taxes, were being reflected in rates charged to customers and are being recovered over the next one to 19 years.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

NOTE 5
Derivative Instruments
The Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, on January 1, 2001. SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

SFAS No. 133 requires that as of the date of initial adoption, the difference between the fair market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivative instruments be reported in net income or other comprehensive income (loss), as appropriate, as the cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, "Accounting Changes." On January 1, 2001, the Company reported a net-of-tax cumulative-effect adjustment of $6.1 million in accumulated other comprehensive loss to recognize at fair value all derivative instruments that are designated as cash flow hedging instruments, which the Company reclassified into earnings during the year ended December 31, 2001. The transition to SFAS No. 133 did not have an effect on the Company's net income at adoption.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; or if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting will be discontinued, and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity.

As of December 31, 2003, an indirect wholly owned subsidiary of the Company held derivative instruments designated as cash flow hedging instruments.

Hedging activities
The subsidiary of the Company utilizes natural gas and oil price swap and collar agreements to manage a portion of the market risk associated with fluctuations in the

price of natural gas and oil on the subsidiary's forecasted sales of natural gas and oil production. Each of the natural gas and oil price swap and collar agreements was designated as a hedge of the forecasted sale of natural gas and oil production.

On an ongoing basis, the balance sheet is adjusted to reflect the current fair market value of the swap and collar agreements. The related gains or losses on these agreements are recorded in common stockholders' equity as a component of other comprehensive income (loss). At the date the underlying transaction occurs, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the years ended December 31, 2003, 2002 and 2001, the subsidiary of the Company recognized the ineffectiveness of cash flow hedges, which is included in operating revenues for the natural gas and oil price swap and collar agreements. For the years ended December 31, 2003, 2002 and 2001, the amount of hedge ineffectiveness recognized was immaterial. For the years ended December 31, 2003, 2002 and 2001, the subsidiary did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness and there were no reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2003, the maximum term of the subsidiary's swap and collar agreements, in which the subsidiary of the Company is hedging its exposure to the variability in future cash flows for forecasted transactions, is 12 months. The subsidiary of the Company estimates that over the next 12 months net losses of approximately $3.3 million will be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Foreign currency derivative
MDU Brasil has a 49 percent equity investment in the Brazil Generating Facility, which has a portion of its borrowings and payables denominated in U.S. dollars. MDU Brasil has exposure to currency exchange risk as a result of fluctuations in currency exchange rates between the U.S. dollar and the Brazilian real. On August 12, 2002, MDU Brasil entered into a foreign currency collar agreement for a notional amount of $21.3 million with a fixed price floor of R$3.10 and a fixed price ceiling of R$3.40 to manage a portion of its foreign currency risk. The term of the collar agreement was from August 12, 2002, through February 3, 2003, and the collar agreement settled on February 3, 2003. The foreign currency collar agreement was not designated as a hedge and was recorded at fair value on the Consolidated Balance Sheets. Gains or losses on this derivative instrument were recorded in other income - net. The Company recorded a gain of $39,000 (after tax) on the foreign currency collar agreement for the year ended December 31, 2003, and a gain of $566,000 (after tax) for the year ended December 31, 2002.

Energy marketing
The Company had entered into other derivative instruments that were not designated as hedges in its energy marketing operations. In the third quarter of 2001, the Company sold the vast majority of its energy marketing operations. Net unrealized gains and losses on these derivative instruments were not material for the year ended December 31, 2001.

NOTE 6
Fair Value of Other Financial Instruments
The estimated fair value of the Company's long-term debt and preferred stock subject to mandatory redemption is based on quoted market prices of the same or similar issues. As discussed in Note 1, the Company, upon adoption of SFAS No. 150 in 2003, began reporting its preferred stock subject to mandatory redemption as a liability. The estimated fair values of the Company's natural gas and oil price swap and collar agreements were included

in current liabilities at December 31, 2003 and 2002. The estimated fair value of the Company's foreign currency collar agreement was included in current assets at December 3 2002. The estimated fair values of the Company's natural gas and oil price swap and collar agreements and foreign currency collar agreement reflect the estimated amounts th Company would receive or pay to terminate the contracts at the reporting date based upon quoted market prices of comparable contracts.

The estimated fair value of the Company's long-term debt, preferred stock subject to mandatory redemption, natural gas and oil price swap and collar agreements and foreign currency collar agreement at December 31 was as follows:

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$ 967,096	$ 1,012,547	$ 841,641	$ 888,066
Preferred stock subject to mandatory redemption	$ ---	$ ---	$ 1,300	$ 1,168
Natural gas and oil price swap and collar agreements	$ (5,467)	$ (5,467)	$ (7,444)	$ (7,444)
Foreign currency collar agreement	$ ---	$ ---	$ 903	$ 903

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities (excluding unsettled derivative instruments) approximate their fair values because of their short-term nature.

NOTE 7
Short-term Borrowings
MDU Resources Group, Inc.
At December 31, 2002, $8.0 million of MDU Resources Group, Inc. (MDU Resources) commercia paper program borrowings were classified as short-term borrowings. The commercial paper borrowings classified as short term were supported by short-term bank lines of credit. There were no amounts outstanding under the bank lines of credit at December 31, 2002. MDU Resources did not have any short-term bank lines of credit at December 31, 2003. For more information on MDU Resources' commercial paper program, see Note 8.

International operations
A subsidiary of the Company had a short-term credit agreement that expired in 2003. Unde this agreement $12.0 million was outstanding at December 31, 2002.

NOTE 8
Long-term Debt and Indenture Provisions
Long-term debt outstanding at December 31 was as follows:

	2003	2002
	(In thousands)	
First mortgage bonds and notes:		
Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, due June 1, 2022	$ 20,850	$ 20,850
Secured Medium-Term Notes, Series A at a weighted average rate of 7.59%, due on dates ranging from October 1, 2004 to April 1, 2012	110,000	110,000
Senior Notes, 5.98%, due December 15, 2033	30,000	---
Total first mortgage bonds and notes	160,850	130,850

Senior notes at a weighted average rate of 6.24%, due on dates ranging from October 30, 2004 to October 30, 2018	718,000	549,100
Commercial paper at a weighted average rate of 1.12%, supported by revolving credit agreements	72,500	151,900
Term credit agreements at a weighted average rate of 5.14%, due on dates ranging from July 15, 2004 to December 1, 2013	14,286	7,873
Pollution control note obligation, 6.20%, due March 1, 2004	1,500	2,000
Discount	(40)	(82)
Total long-term debt	967,096	841,641
Less current maturities	27,646	22,083
Net long-term debt	$ 939,450	$ 819,558

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2003, aggregate $27.6 million in 2004; $70.9 million in 2005; $173.2 million in 2006; $105.8 million in 2007; $160.2 million in 2008 and $429.4 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2003.

MDU Resources Group, Inc.
MDU Resources has a revolving credit agreement with various banks totaling $90 million at December 31, 2003. There were no amounts outstanding under the credit agreement at December 31, 2003 and 2002. The credit agreement supports MDU Resources' $75 million commercial paper program. Under the MDU Resources' commercial paper program, $40 million was outstanding at December 31, 2003, which was classified as long-term debt, and $58.0 million was outstanding at December 31, 2002, of which $8.0 million was classified as short-term borrowings and $50.0 million was classified as long-term debt. As discussed in Note 7, the commercial paper borrowings classified as short term were supported by short-term bank lines of credit. The commercial paper borrowings classified as long-term debt are intended to be refinanced on a long-term basis through continued MDU Resources commercial paper borrowings and as further supported by the credit agreement, which expires on July 18, 2006.

In order to borrow under the MDU Resources credit agreement, MDU Resources must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum leverage ratios, minimum interest coverage ratio, limitation on sale of assets and limitation on investments. MDU Resources was in compliance with these covenants and met the required conditions at December 31, 2003.

There are no credit facilities that contain cross-default provisions between MDU Resources and any of its subsidiaries.

MDU Resources' issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Indenture of Mortgage. Generally, those restrictions require MDU Resources to pledge $1.43 of unfunded property to the trustee for each dollar of indebtedness incurred under the Indenture and that annual earnings (pretax and before interest charges), as defined in the Indenture, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the two tests, as of December 31, 2003, MDU Resources could have issued approximately $313 million of additional first mortgage bonds.

Approximately $421.2 million of the Company's net electric and natural gas distribution properties at December 31, 2003, with certain exceptions, are subject to the lien of the Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustee, and are subject to the junior lien of the Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York, as trustee.

Centennial Energy Holdings, Inc.
Centennial Energy Holdings, Inc. (Centennial) has two revolving credit agreements with various banks that support $275 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2003 or 2002. Under the Centennial commercial paper program, $32.5 million and $101.9 million were outstanding at December 31, 2003 and 2002, respectively. The Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings and as further supported by the Centennial credit agreements. The Centennial credit agreements are for $137.5 million each. One of these agreements expires on September 3, 2004, and allows for subsequent borrowings up to a term of one year. The other agreement expires on September 5, 2006. Centennial intends to negotiate the extension or replacement of these agreements prior to their maturities.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $400 million. Under the terms of the master shelf agreement, $384.0 million was outstanding at December 31, 2003, and $360.6 million was outstanding at December 31, 2002. The amount outstanding under the uncommitted long-term master shelf agreement is included in senior notes in the preceding long-term debt table.

In order to borrow under Centennial's credit agreements and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum capitalization ratios, minimum interest coverage ratios, minimum consolidated net worth, limitation on priority debt, limitation on sale of assets and limitation on loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2003.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default. Certain of Centennial's financing agreements and Centennial's practice limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company
Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of the Company, has an uncommitted long-term master shelf agreement that allows for borrowings of up to $100 million. Under the terms of the master shelf agreement, $55.0 million and $30.0 million was outstanding at December 31, 2003 and 2002, respectively.

In order to borrow under Williston Basin's uncommitted long-term master shelf agreement, it must be in compliance with the applicable covenants and certain other conditions. The significant covenants include limitation on consolidated indebtedness, limitation on priority debt, limitation on sale of assets and limitation on investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2003.

NOTE 9
Asset Retirement Obligations

The Company adopted SFAS No. 143 on January 1, 2003, as discussed in Note 1. The Company recorded obligations related to the plugging and abandonment of natural gas and oil wells decommissioning of certain electric generating facilities, reclamation of certain aggregate properties and certain other obligations associated with leased properties. Removal costs associated with certain natural gas distribution, transmission, storage and gathering facilities have not been recognized as these facilities have been determined to have indeterminate useful lives.

Upon adoption of SFAS No. 143, the Company recorded an additional discounted liability of $22.5 million and a regulatory asset of $493,000, increased net property, plant and equipment by $9.6 million and recognized a one-time cumulative effect charge of $7.6 million (net of deferred income tax benefits of $4.8 million). The Company believes that any expenses under SFAS No. 143 as they relate to regulated operations will be recovered in rates over time and accordingly, deferred such expenses as a regulatory asset upon adoption. The Company will continue to defer those SFAS No. 143 expenses that it believes will be recovered in rates over time. In addition to the $22.5 million liability recorded upon the adoption of SFAS No. 143, the Company had previously recorded a $7.5 million liability related to retirement obligations.

A reconciliation of the Company's liability for the year ended December 31 was as follows:

	2003 (In thousands)
Balance at January 1, 2003	$29,997
Liabilities incurred	2,405
Liabilities acquired	1,803
Liabilities settled	(1,555)
Accretion expense	1,906
Revisions in estimates	77
Balance at December 31, 2003	$34,633

This liability is included in other liabilities. If SFAS No. 143 had been in effect during 2002 and 2001, the Company's liability would have been approximately $30.0 million at December 31, 2002, and $27.0 million at December 31, 2001.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2003, was $5.1 million.

NOTE 10
Preferred Stocks
Preferred stocks at December 31 were as follows:

	2003	2002
	(Dollars in thousands)	
Authorized:		
Preferred --		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A --		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference --		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
Subject to mandatory redemption --		
Preferred --		
5.10% Series - 13,000 shares in 2002	$ ---	$ 1,300
Other preferred stock --		
4.50% Series -- 100,000 shares	10,000	10,000
4.70% Series -- 50,000 shares	5,000	5,000

	15,000	15,000
Total preferred stocks	15,000	16,300
Less sinking fund requirements	---	100
Net preferred stocks	$ 15,000	$ 16,200

As discussed in Note 1, the Company upon adoption of SFAS No. 150 in 2003, began reportin its preferred stock subject to mandatory redemption as a liability. Restatement of prior year information is not permitted under SFAS No. 150.

The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 and $102, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holder are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or by-laws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates tc a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certai exceptions; or the partial retirement of that series of preferred stock when all dividend on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of al outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or i part, for one year the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

NOTE 11
Common Stock
On August 14, 2003, the Company's Board of Directors approved a three-for-two common stoc split to be effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on October 29, 2003, to common stockholders of record on October 10, 2003. Common stock information appearing in the accompanying consolidated financial statements has been restated to give retroactive effect to the stock split. Additionally, preference share purchase rights have been appropriately adjusted to reflect the effects of the split.

At the Annual Meeting of Stockholders held on April 23, 2002, the Company's common stockholders approved an amendment to the Certificate of Incorporation increasing the authorized number of common shares from 150 million shares to 250 million shares with a par value of $1.00 per share.

The Company's Dividend Reinvestment and Direct Stock Purchase Plan (Stock Purchase Plan) provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The Company's 401(k) Retirement Plan (K-Plan) is partially funded with the Company's common stock. Since January 1, 2001, the Stock Purchase Plan and K-Plan, with respect to Company stock, have been funded by the purchase of shares of common stock on the open market. At December 31, 2003, there were 12.1 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

In November 1998, the Company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the Company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for two-thirds of one one-thousandth of a share of Series B Preference Stock of the Company, without par value, at an exercise price of $125, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the Company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the Company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of two-thirds of one one-thousandth of a Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.00667 per right, at the Company's option at any time until any acquiring person has acquired 15 percent or more of the Company's common stock.

NOTE 12
Stock-based Compensation

The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123 and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. As permitted by SFAS No. 148, the Company accounts for stock options granted prior to January 1, 2003, under APB Opinion No. 25.

For a discussion of the adoption of SFAS No. 123 and the effect on earnings and earnings per common share for the years ended December 31, 2003, 2002 and 2001, as if the Company had applied SFAS No. 123, and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant, see Note 1.

Options granted to key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expire 10 years after the date of grant. Options granted to directors and employees vest at date of grant and three years after date of grant, respectively, and expire 10 years after the date of grant.

A summary of the status of the stock option plans at December 31, 2003, 2002 and 2001, and changes during the years then ended was as follows:

	2003		2002		2001	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	4,861,268	$18.58	5,208,311	$18.60	1,837,439	$13.74
Granted	27,015	17.29	160,605	19.15	4,039,680	20.09
Forfeited	(188,486)	20.05	(453,840)	19.77	(111,423)	18.16
Exercised	(517,341)	13.88	(53,808)	12.20	(557,385)	13.49
Balance at end of year	4,182,456	19.09	4,861,268	18.58	5,208,311	18.60
Exercisable at end of year	611,404	$15.06	1,135,050	$14.56	1,155,213	$14.27

Summarized information about stock options outstanding and exercisable as of December 31, 2003, was as follows:

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 8.22 - 13.00	23,451	2.5	$ 9.77	23,451	$ 9.77
13.01 - 17.00	647,085	4.3	14.13	511,453	14.15
17.01 - 21.00	3,302,115	7.2	19.77	36,000	19.54
21.01 - 25.70	209,805	7.2	24.56	40,500	25.70
Balance at end of year	4,182,456	6.7	19.09	611,404	15.06

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options were as follows:

	2003	2002	2001
Weighted average fair value of options at grant date	$4.67	$5.38	$4.92
Weighted average risk-free interest rate	3.91%	5.14%	5.19%
Weighted average expected price volatility	32.28%	30.80%	26.05%
Weighted average expected dividend yield	3.43%	3.43%	3.53%
Expected life in years	7	7	7

In addition, the Company granted restricted stock awards under a long-term incentive pla and deferred compensation agreements totaling 525,588 shares in 2001. The restricted stock awards granted vest to the participants at various times ranging from two years to nine years from date of issuance, but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the Company. The weighted average grant date fair value of the restricted stock grant in 2001 was $21.03. The Company also has granted stock awards totaling 31,855 shares, 21,390 shares and 19,0 shares in 2003, 2002 and 2001, respectively, under a nonemployee director stock compensation plan. The weighted average grant date fair value of the stock grants was $21.40, $19.20 and $20.09, in 2003, 2002 and 2001, respectively. Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. Compensation expense recognized for restricted stock grants and stock grants was $4.8 million, $5.2 million and $4.9 million in 2003, 2002 and 2001, respectively.

In 2003, key employees of the Company were awarded performance share awards. Entitlemen to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. Target grants of performance shares were made for the following performance periods:

Grant Date	Performance Period	Target Grant of Shares
February 2003	2003-2004	57,655
February 2003	2003-2005	57,655

Participants may earn additional performance shares if the Company's total shareholder return exceeds that of the selected peer group. The final value of the performance unit may vary according to the number of shares of Company stock that are ultimately granted based on the performance criteria. Compensation expense recognized for the performance share awards for the year ended December 31, 2003, was $879,000.

The Company is authorized to grant options, restricted stock and stock for up to 14.3 million shares of common stock and has granted options, restricted stock and stock on 6.

million shares through December 31, 2003.

NOTE 13
Income Taxes
Income tax expense for the years ended December 31 was as follows:

	2003	2002	2001
		(In thousands)	
Current:			
Federal	$ 26,313	$ 46,389	$ 66,211
State	7,408	9,082	11,160
Foreign	264	---	(44)
	33,985	55,471	77,327
Deferred:			
Income taxes --			
Federal	55,660	26,373	16,972
State	9,861	4,632	4,773
Foreign	(338)	338	---
Investment tax credit	(596)	(584)	(731)
	64,587	30,759	21,014
Total income tax expense	$ 98,572	$ 86,230	$ 98,341

Components of deferred tax assets and deferred tax liabilities recognized at December 31 were as follows:

	2003	2002
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 37,072	$ 34,792
Accrued pension costs	12,122	12,112
Deferred compensation	9,090	6,395
Asset retirement obligations	7,017	263
Bad debts	3,188	2,798
Deferred investment tax credit	954	1,185
Other	21,269	18,444
Total deferred tax assets	90,712	75,989
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	406,589	354,842
Basis differences on natural gas and oil producing properties	105,826	70,464
Regulatory matters	10,663	5,491
Other	9,309	10,412
Total deferred tax liabilities	532,387	441,209
Net deferred income tax liability	$(441,675)	$(365,220)

As of December 31, 2003 and 2002, no valuation allowance has been recorded associated wit
the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2002, to December 31, 2003, to deferred income tax expense:

	2003
	(In thousands)
Net change in deferred income tax liability from the preceding table	$ 76,455
Deferred taxes associated with acquisitions	(15,056)
Deferred taxes associated with the cumulative effect of accounting change	4,821
Deferred taxes associated with other comprehensive income	(809)
Other	(824)
Deferred income tax expense for the period	$ 64,587

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	2003 Amount	2003 %	2002 Amount	2002 %	2001 Amount	2001 %
	(Dollars in thousands)					
Computed tax at federal statutory rate	$ 98,520	35.0	$ 82,136	35.0	$ 88,966	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	11,857	4.2	10,279	4.4	11,311	4.5
Investment tax credit amortization	(596)	(.2)	(584)	(.3)	(731)	(.3)
Depletion allowance	(3,117)	(1.1)	(2,200)	(.9)	(1,820)	(.7)
Renewable electricity production credit	(3,395)	(1.2)	---	---	---	---
Other items	(4,697)	(1.7)	(3,401)	(1.5)	615	.2
Total income tax expense	$ 98,572	35.0	$ 86,230	36.7	$ 98,341	38.7

The Company considers earnings from its foreign equity method investment in a natural gas-fired electric generating facility in Brazil to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes are recorded with respect to such earnings. Should the earnings be remitted as dividends, the Company may be subject to additional U.S. taxes, net of allowable foreign tax credits.

NOTE 14
Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The Company has six reportable segment consisting of electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, and construction materials and mining. During the fourth quarter of 2002, the Company separated independent power production and other operations from its reportable segments. The independent power production and other operations do not individually meet the criteria to be considered a reportable segment. Substantially all of the operations of independent power production and other began in 2002; therefore, financial information for years prior to 2002 has not been presented.

The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of an investmen in a natural gas-fired electric generating facility in Brazil, as discussed in Note 2. The electric segment generates, transmits and distributes electricity, and the natural g distribution segment distributes natural gas. These operations also supply related value-added products and services in the northern Great Plains. The utility services segment specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling and the manufacture and distribution of specialty equipmen The pipeline and energy services segment provides natural gas transportation, undergroun storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The pipeline and energy services segment also provides energy-related management service including cable and pipeline magnetization and locating. The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration and production activities, primarily in the Rocky Mountain region of the United States and i and around the Gulf of Mexico. The construction materials and mining segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt and other value-added products, as well performs integrated construction services, in the central and western United States and

the states of Alaska and Hawaii. The independent power production and other operations own electric generating facilities in the United States and have an investment in an electric generating facility in Brazil. Electric capacity and energy produced at these facilities are primarily sold under long-term contracts to nonaffiliated entities. These operations also include investments in opportunities that are not directly being pursued by the Company's other businesses.

In 2001, the Company sold its coal operations to Westmoreland Coal Company for $28.2 million in cash and recorded a gain of $10.3 million ($6.2 million after tax) included in other income - net. The sale of the Company's coal operations included active coal mines in North Dakota and Montana, coal sales agreements, reserves and mining equipment, and certain development rights at the Company's former Gascoyne Mine site in North Dakota. The Company retained ownership of lignite deposits and leases at its former Gascoyne Mine site in North Dakota, which were not part of the sale of the coal operations. The Gascoyne Mine site was closed in 1995 due to the cancellation of the coal sale contract. These lignite deposits are currently not being mined and are not associated with an operating mine. These lignite deposits are of a high moisture content and it is not economical to mine and ship the lignite to other distant markets. However, should a power plant be constructed near the area, the Company may have the opportunity to participate in supplying lignite to fuel a plant. As of December 31, 2003, Knife River had under ownership or lease, deposits of approximately 26.9 million tons of recoverable lignite coal.

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2003	2002	2001
		(In thousands)	
External operating revenues:			
Electric	$ 178,562	$ 162,616	$ 168,837
Natural gas distribution	274,608	186,569	255,389
Pipeline and energy services	187,892	110,224	479,108
	641,062	459,409	903,334
Utility services	434,177	458,660	364,746
Natural gas and oil production	140,281	148,158	148,653
Construction materials and mining	1,104,408	962,312	806,899(a)
Independent power production and other	32,261	2,998	---
	1,711,127	1,572,128	1,320,298
Total external operating revenues	$ 2,352,189	$ 2,031,537	$ 2,223,632
Intersegment operating revenues:			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	---	---	4
Pipeline and energy services	64,300	55,034	52,006
Natural gas and oil production	124,077	55,437	61,178
Construction materials and mining	---	---	---
Independent power production and other	2,728	3,778	---
Intersegment eliminations	(191,105)	(114,249)	(113,188)
Total intersegment operating revenues	$ ---	$ ---	$ ---
Depreciation, depletion and amortization:			
Electric	$ 20,150	$ 19,537	$ 19,488
Natural gas distribution	10,044	9,940	9,337
Utility services	10,353	9,871	8,395

Pipeline and energy services	15,016	14,846	14,341
Natural gas and oil production	61,019	48,714	41,690
Construction materials and mining	63,601	54,334	46,666
Independent power production and other	8,154	719	---
Total depreciation, depletion and amortization	$ 188,337	$ 157,961	$ 139,917
Interest expense:			
Electric	$ 8,013	$ 7,621	$ 8,531
Natural gas distribution	3,936	4,364	3,727
Utility services	3,668	3,568	3,807
Pipeline and energy services	7,952	7,670	9,136
Natural gas and oil production	4,767	2,464	1,359
Construction materials and mining	18,747	18,422	19,339
Independent power production and other	5,865	1,122	---
Intersegment eliminations	(154)	(216)	---
Total interest expense	$ 52,794	$ 45,015	$ 45,899

	2003	2002 (In thousands)	2001
Income taxes:			
Electric	$ 9,862	$ 9,501	$ 10,511
Natural gas distribution	1,823	(1,325)	1,067
Utility services	3,905	4,781	9,131
Pipeline and energy services	11,188	12,462	11,633
Natural gas and oil production	42,993	30,604	40,486
Construction materials and mining	28,168	29,415	25,513
Independent power production and other	633	792	---
Total income taxes	$ 98,572	$ 86,230	$ 98,341
Cumulative effect of accounting change (Note 9):			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	---	---	---
Pipeline and energy services	---	---	---
Natural gas and oil production	(7,740)	---	---
Construction materials and mining	151	---	---
Independent power production and other	---	---	---
Total cumulative effect of accounting change	$ (7,589)	$ ---	$ ---
Earnings on common stock:			
Electric	$ 16,950	$ 15,780	$ 18,717
Natural gas distribution	3,869	3,587	677
Utility services	6,170	6,371	12,910
Pipeline and energy services	18,158	19,097	16,406
Natural gas and oil production	63,027	53,192	63,178
Construction materials and mining	54,412	48,702	43,199
Independent power production and other	12,021	959	---
Total earnings on common stock	$ 174,607	$ 147,688	$ 155,087
Capital expenditures:			
Electric	$ 28,537	$ 27,795	$ 14,373

Natural gas distribution	15,672	11,044	14,685
Utility services	7,820	17,242	70,232
Pipeline and energy services	93,004	21,449	51,054
Natural gas and oil production	101,698	136,424	118,719
Construction materials and mining	128,487	106,893	170,585
Independent power production and other	112,858	95,748	---
Net proceeds from sale or disposition of property	(14,439)	(16,217)	(51,641)
Total net capital expenditures	$ 473,637	$ 400,378	$ 388,007

	2003	2002 (In thousands)	2001
Identifiable assets:			
Electric(b)	$ 327,899	$ 322,475	$ 301,982
Natural gas distribution(b)	234,948	208,502	217,402
Utility services	221,824	230,888	239,069
Pipeline and energy services	405,904	312,858	354,336
Natural gas and oil production	602,389	554,420	476,105
Construction materials and mining	1,248,607	1,137,697	1,035,929
Independent power production and other	263,941	148,770	---
Corporate assets(c)	75,080	81,311	51,155
Total identifiable assets	$ 3,380,592	$ 2,996,921	$ 2,675,978
Property, plant and equipment:			
Electric(b)	$ 639,893	$ 619,230	$ 597,080
Natural gas distribution(b)	252,591	244,930	235,771
Utility services	76,871	70,660	59,190
Pipeline and energy services	461,793	372,420	369,775
Natural gas and oil production	871,357	755,788	630,826
Construction materials and mining	893,980	804,255	711,410
Independent power production and other	201,134	94,525	---
Less accumulated depreciation, depletion and amortization	1,175,326	1,019,438	889,816
Net property, plant and equipment	$ 2,222,293	$ 1,942,370	$ 1,714,236

(a) In accordance with the provision of SFAS No. 71, intercompany coal sales of $5,016 in 2001 were not eliminated.
(b) Includes allocations of common utility property.
(c) Corporate assets consist of assets not directly assignable to a business (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).

Earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from utility services, natural gas and oil production, construction materials and mining, and independent power production and other are all from nonregulated operations. Capital expenditures for 2003, 2002 and 2001, related to acquisitions, in the preceding table included the following noncash transactions: issuance of the Company's equity securities of $42.4 million, $47.2 million and $57.4 million in 2003, 2002 and 2001, respectively.

NOTE 15
Acquisitions
In 2003, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Montana, North Dakota and Texas and a wind-powered electric generation facility in California. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired in 2002, including the Company's common stock and cash, was $175.0

million.

In 2002, the Company acquired a number of businesses, none of which was individually material, including utility services companies in California and Ohio, construction materials and mining businesses in Minnesota and Montana, an energy development company i Montana and natural gas-fired electric generating facilities in Colorado. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $139.8 million.

In 2001, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Minnesota and Oregon; utility services businesses based in Missouri and Oregon; and an energy services company specializing in cable and pipeline locating and tracking systems. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $170.1 million.

On April 1, 2000, Fidelity Exploration & Production Company (Fidelity), an indirect wholl owned subsidiary of the Company, purchased substantially all of the assets of Preston Reynolds & Co., Inc. (Preston), a coalbed natural gas development operation based in Colorado with related oil and gas leases and properties in Montana and Wyoming. Pursuant to the asset purchase and sale agreement, Preston could, but was not obligated to purchase, acquire and own an undivided 25 percent working interest (Seller's Option Interest) in certain oil and gas leases or properties acquired and/or generated by Fidelity. Fidelity had the right, but not the obligation, to purchase Seller's Option Interest from Preston for an amount as specified in the agreement. On July 10, 2002, Fidelity purchased the Seller's Option Interest.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. Final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date on certain of the above acquisitions made in 2003. The results of operations of the acquired businesses are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting th effects of the above acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

NOTE 16
Employee Benefit Plans
The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans. These financial statements and this Note do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plans. For more information on the 2003 Medicare Act, see new accounting standards in Note 1. Changes in benefit obligation and plan assets for the years ended December 31 and amounts recognized in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$224,766	$204,046	$ 74,917	$ 67,019
Service cost	5,897	5,135	1,857	1,460
Interest cost	15,211	14,877	5,281	4,915
Plan participants' contributions	---	---	977	834
Amendments	210	372	754	---

Actuarial loss	27,701	12,324	10,338	5,678
Benefits paid	(12,450)	(11,988)	(5,743)	(4,989)
Benefit obligation at end of year	261,335	224,766	88,381	74,917
Change in plan assets:				
Fair value of plan assets at beginning of year	189,143	224,667	40,889	45,175
Actual gain (loss) on plan assets	43,087	(26,543)	6,148	(4,196)
Employer contribution	3,263	3,007	4,963	4,065
Plan participants' contributions	---	---	977	834
Benefits paid	(12,450)	(11,988)	(5,743)	(4,989)
Fair value of plan assets at end of year	223,043	189,143	47,234	40,889
Funded status - over (under)	(38,292)	(35,623)	(41,147)	(34,028)
Unrecognized actuarial loss	41,422	35,662	11,862	3,484
Unrecognized prior service cost	8,556	9,501	706	---
Unrecognized net transition obligation (asset)	(297)	(1,247)	19,362	21,513
Prepaid (accrued) benefit cost	$ 11,389	$ 8,293	$ (9,217)	$ (9,031)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost	$ 19,671	$ 16,175	$ 614	$ 780
Accrued benefit liability	(8,282)	(7,882)	(9,831)	(9,811)
Additional minimum liability	---	(4,905)	---	---
Intangible asset	---	533	---	---
Accumulated other comprehensive loss	---	4,372	---	---
Net amount recognized	$ 11,389	$ 8,293	$ (9,217)	$ (9,031)

Employer contributions and benefits paid in the above table include only those amounts contributed directly to, or paid directly from, plan assets.

The accumulated benefit obligation for the defined benefit pension plans reflected above was $212.0 million and $186.4 million at December 31, 2003 and 2002, respectively.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan asse at December 31, 2003, were as follows:

	2003	2002
	(In thousands)	
Projected benefit obligation	$ 38,845	$32,768
Accumulated benefit obligation	$ 28,840	$24,656
Fair value of plan assets	$ 24,508	$20,615

Components of net periodic benefit cost (income) for the Company's pension and other postretirement benefit plans were as follows:

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	2003	2002	2001	2003	2002	2001
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	$ 5,897	$ 5,135	$ 4,716	$ 1,857	$ 1,460	$ 1,376
Interest cost	15,211	14,877	14,498	5,281	4,915	4,691

Expected return on assets	(20,730)	(21,110)	(20,672)	(3,933)	(3,843)	(3,619)
Amortization of prior service cost	1,156	1,148	1,247	48	---	---
Recognized net actuarial gain	(417)	(1,855)	(2,687)	(255)	(566)	(930)
Settlement (gain) loss	---	---	(884)	---	---	15
Amortization of net transition obligation (asset)	(950)	(947)	(965)	2,151	2,151	2,227
Net periodic benefit cost (income)	167	(2,752)	(4,747)	5,149	4,117	3,760
Less amount capitalized	14	(352)	(391)	601	404	329
Net periodic benefit cost (income)	$ 153	$ (2,400)	$(4,356)	$ 4,548	$ 3,713	$ 3,431

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Discount rate	6.00%	6.75%	6.00%	6.75%
Rate of compensation increase	4.70%	4.50%	4.50%	4.50%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	4.50%	5.00%	4.50%	5.00%

The expected rate of return on plan assets is based on the targeted asset allocation of 7 percent equity securities and 30 percent fixed income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2003	2002
Health care trend rate assumed for next year	6.0%-9.5%	6.0%-11.0%
Health care cost trend rate - ultimate	5.0%-6.0%	5.0%-6.0%
Year in which ultimate trend rate achieved	1999-2012	1999-2011

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2003:

	1 Percentage	1 Percentage

	Point Increase	Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 250	$ (972)
Effect on postretirement benefit obligation	$ 3,479	$(9,554)

The Company's defined benefit pension plans asset allocation at December 31, 2003 and 2002, and weighted average targeted asset allocations at December 31, 2003, were as follows:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	2003	2002	2003
Equity securities	72%	56%	70%
Fixed income securities	25	40	30*
Other	3	4	---
Total	100%	100%	100%

*Includes target for both fixed income securities and other.

The Company's pension assets are managed by nine outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed income securities and equity securities. The guidelines prohibit investment in commodities and future contracts, equity private placement, employer securities and leveraged or derivative securities. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

The Company's other postretirement benefit plans asset allocation at December 31, 2003 and 2002, and weighted average targeted asset allocation at December 31, 2003, were as follows:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	2003	2002	2003
Equity securities	66%	50%	70%
Fixed income securities	30	45	30*
Other	4	5	---
Total	100%	100%	100%

*Includes target for both fixed income securities and other.

The Company expects to contribute approximately $1.6 million to its defined benefit pension plans and approximately $5.0 million to its postretirement benefit plans in 2004.

In addition to company-sponsored plans, certain employees are covered under multi-employer defined benefit plans administered by a union. Amounts contributed to the multi-employer plans were $27.2 million, $27.8 million and $19.9 million in 2003, 2002 and 2001, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of Note 16, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that provides for defined benefit payments upon the employee's retirement or to their beneficiaries upon death for a 15-yea period or as an equivalent life annuity. Investments consist of life insurance carried c plan participants, which is payable to the Company upon the employee's death. The cost c these benefits was $5.3 million, $5.1 million and $4.3 million in 2003, 2002 and 2001, respectively. The total projected obligation for this plan was $51.1 million and $40.5 million at December 31, 2003 and 2002, respectively. The accumulated benefit obligation for this plan was $40.7 million and $33.3 million at December 31, 2003 and 2002, respectively. The additional minimum liability relating to this plan was $8.2 million an $4.0 million at December 31, 2003 and 2002, respectively. The Company has a related intangible asset recognized as of December 31, 2003 and 2002, of $1.0 million and $1.1 million, respectively. A discount rate of 6.0 percent and 6.75 percent at December 31, 2003 and 2002, respectively, and a rate of compensation increase of 4.75 percent and 4.50 percent at December 31, 2003 and 2002, respectively, were used to determine benefit obligations.

A discount rate of 6.75 percent and 7.25 percent at December 31, 2003 and 2002, respectively, and a rate of compensation increase of 4.50 percent and 5.00 percent at December 31, 2003 and 2002, respectively, were used to determine net periodic benefit cost. The increase in minimum liability included in other comprehensive income was $2.6 million in 2003 and $1.8 million in 2002.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $9.8 million in 2003, $9.6 million in 2002 and $7.2 million in 2001. The costs incurred in each year reflect additional participant as a result of business acquisitions.

NOTE 17
Jointly Owned Facilities
The consolidated financial statements include the Company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the Big Stone Station and Coyote Station operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2003	2002
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 52,154	$ 53,018
Less accumulated depreciation	34,993	34,456
	$ 17,161	$ 18,562
Coyote Station:		
Utility plant in service	$ 124,086	$ 122,476
Less accumulated depreciation	72,850	70,778
	$ 51,236	$ 51,698

NOTE 18
Regulatory Matters and Revenues Subject To Refund
On May 30, 2003, Montana-Dakota Utilities Co. (Montana-Dakota), a public utility division of MDU Resources, filed an application with the North Dakota Public Service Commission (NDPSC) for an electric rate increase. Montana-Dakota requested a total of $7.8 million annually or 9.1 percent above current rates. On July 23, 2003, Montana-Dakota and the NDPSC Staff filed a Settlement Agreement with the NDPSC agreeing on the issues of rate of

return, capital structure and cost of capital components. On October 22, 2003, the NDPSC approved the Settlement Agreement. On November 19, 2003, Montana-Dakota and the NDPSC Staff filed an additional Settlement Agreement to resolve all remaining outstanding issue with the NDPSC. This Settlement Agreement reflected an increase of $1.0 million annually and a sharing mechanism between Montana-Dakota and retail customers of wholesale electric sales margins. On December 18, 2003, the NDPSC approved the November 2003 Settlement Agreement and required Montana-Dakota to file a compliance filing with the NDPSC. On January 14, 2004, the NDPSC approved Montana-Dakota's compliance filing, which was filed on January 7, 2004, with rates effective with service rendered on and after January 23, 2004.

In December 2002, Montana-Dakota filed an application with the South Dakota Public Utilities Commission (SDPUC) for a natural gas rate increase. Montana-Dakota requested a total of $2.2 million annually or 5.8 percent above current rates. On October 27, 2003, Montana-Dakota and the SDPUC Staff filed a Settlement Stipulation with the SDPUC agreeing to an increase of $1.3 million annually. On December 2, 2003, the SDPUC approved the Settlement Stipulation effective with service rendered on and after December 2, 2003.

In October 2002, Great Plains Natural Gas Co. (Great Plains), a public utility division o MDU Resources, filed an application with the Minnesota Public Utilities Commission (MPUC) for a natural gas rate increase. Great Plains requested a total of $1.6 million annually or 6.9 percent above current rates. In December 2002, the MPUC issued an Order setting interim rates that approved an interim increase of $1.4 million annually effective December 6, 2002. Great Plains began collecting such rates effective December 6, 2002, subject to refund until the MPUC issued a final order. On October 9, 2003, the MPUC issued a Final Order authorizing an increase of $1.1 million annually and requiring Great Plains to file a compliance filing with the MPUC. On January 16, 2004, the MPUC issued a Order accepting Great Plains' compliance filing, which was filed on November 10, 2003, effective with service rendered on and after January 16, 2004.

Reserves have been provided for a portion of the revenues that have been collected subjec to refund for certain of the above proceedings. The Company believes that such reserves are adequate based on its assessment of the ultimate outcome of the proceedings.

In December 1999, Williston Basin filed a general natural gas rate change application wit the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. In May 2001, the Administrative Law Judge (ALJ) issued an Initial Decision on Williston Basin's natural gas rate change application. The Initial Decision addressed numerous issues relating to the rate change application, including matters relating to allowable levels of rate base, return on common equity, and cost of service, as well as volumes established for purposes of cost recovery, and cost allocation and rate design. On July 3, 2003, the FERC issued its Order on Initial Decision. The Order on Initial Decision affirmed the ALJ's Initial Decision on many of the issues including rate base an certain cost of service items as well as volumes to be used for purposes of cost recovery and cost allocation and rate design. However, there are other issues as to which the FER differed with the ALJ including return on common equity and the correct level of corporat overhead expense. On August 4, 2003, Williston Basin requested a rehearing of a number c issues including determinations associated with cost of service, throughput, and cost allocation and rate design, as discussed in the FERC's Order on Initial Decision. On September 3, 2003, the FERC issued an Order granting Williston Basin's request for rehearing of the July 3, 2003, Order on Initial Decision. The Company is awaiting a decision from the FERC on the merits of the Company's rehearing request and is unable to predict the timing of the FERC's decision.

Reserves have been provided for a portion of the revenues that have been collected subjec to refund with respect to Williston Basin's pending regulatory proceeding. Williston Basin believes that such reserves are adequate based on its assessment of the ultimate outcome of the proceeding.

NOTE 19
Commitments and Contingencies
Litigation
In January 2002, Fidelity Oil Co. (FOC), one of the Company's natural gas and oil production subsidiaries, entered into a compromise agreement with the former operator of certain of FOC's oil production properties in southeastern Montana. The compromise agreement resolved litigation involving the interpretation and application of contractual provisions regarding net proceeds interests paid by the former operator to FOC for a number of years prior to 1998. The terms of the compromise agreement are confidential. As a result of the compromise agreement, the natural gas and oil production segment reflected a nonrecurring gain in its financial results for the first quarter of 2002 of approximately $16.6 million after tax. As part of the settlement, FOC gave the former operator a full and complete release, and FOC is not asserting any such claim against the former operator for periods after 1997.

In June 1997, Jack J. Grynberg (Grynberg) filed a Federal False Claims Act suit against Williston Basin and Montana-Dakota and filed over 70 similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. Grynberg acting on behalf of the United States under the Federal False Claims Act, alleged improper measurement of the heating content and volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. In April 1999, the United States Department of Justice decided not to intervene in these cases. In response to a motion filed by Grynberg, the Judicial Panel on Multidistrict Litigation consolidated all of these cases in the Federal District Court of Wyoming.

The matter is currently in the discovery stage. Grynberg has not specified the amount he seeks to recover. Williston Basin and Montana-Dakota are unable to estimate their potential exposure and will be unable to do so until discovery is completed. Williston Basin and Montana-Dakota believe that the Grynberg case will ultimately be dismissed because Grynberg is not, as is required by the Federal False Claims Act, the original source of the information underlying the action. Failing this, Williston Basin and Montana-Dakota believe Grynberg will not recover damages from Williston Basin and Montana-Dakota because insufficient facts exist to support the allegations.

Williston Basin and Montana-Dakota believe the claims of Grynberg are without merit and intend to vigorously contest this suit. Williston Basin and Montana-Dakota believe it is not probable that Grynberg will ultimately succeed given the current status of the litigation.

Fidelity has been named as a defendant in, and/or certain of its operations are the subject of, 11 lawsuits filed in connection with its coalbed natural gas development in the Powder River Basin in Montana and Wyoming. These lawsuits were filed in federal and state courts in Montana between June 2000 and December 2003 by a number of environmental organizations, including the Northern Plains Resource Council and the Montana Environmental Information Center as well as the Tongue River Water Users' Association and the Northern Cheyenne Tribe. Two of the lawsuits have been transferred to Federal District Court in Wyoming. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Federal Clean Water Act and the National Environmental Policy Act. The lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. Fidelity is unable to quantify the damages sought, and will be unable to do so until after completion of discovery. Fidelity is vigorously defending all coalbed-related lawsuits in which it is involved. If the plaintiffs are successful in these lawsuits, the ultimate outcome of these actions could have a material effect on Fidelity's existing coalbed natural gas operations and/or the future development of its coalbed natural gas properties.

Montana-Dakota has joined with two electric generators in appealing a finding by the North Dakota Department of Health (Department) in September 2003 that the Department may unilaterally revise operating permits previously issued to electric generating plants.

Although it is doubtful that any revision of Montana-Dakota's operating permits by the Department would reduce the amount of electricity its plants could generate, the finding, if allowed to stand, could increase costs for sulfur dioxide removal and/or limit Montana-Dakota's ability to modify or expand operations at its North Dakota generation sites. Montana-Dakota and the other electric generators filed their appeal of the order on October 8, 2003, in the Burleigh County District Court in Bismarck, North Dakota. Proceedings have been stayed pending discussions with the United States Environmental Protection Agency (EPA), the Department and the other electric generators.

In a related case, the Dakota Resource Council filed an action in Federal District Court in Denver, Colorado, on September 30, 2003, to require the EPA to enforce certain air quality standards in North Dakota. If successful, the action could require the curtailment of discharges of sulfur dioxide into the atmosphere by existing electric generating facilities and could preclude or hinder the construction of future generating facilities in North Dakota. The Company has filed a Motion to Intervene in the lawsuit and has joined in a brief supporting a Motion to Dismiss filed by the EPA.

The Company cannot predict the outcome of the Department or Dakota Resource Council matters or their ultimate impact on its operations.

The Company is also involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that the outcomes with respect to these other legal proceedings will not have a material adverse effect upon the Company's financial position or results of operations.

Environmental matters

In December 2000, Morse Bros., Inc. (MBI), an indirect wholly owned subsidiary of the Company, was named by the EPA as a Potentially Responsible Party in connection with the cleanup of a commercial property site, acquired by MBI in 1999, and part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation of the harbor site for both the EPA and the Oregon State Department of Environmental Quality (DEQ) are being recorded, and initially paid, through an administrative consent order by the Lower Willamette Group (LWG), a group of 10 entities that does not include MBI. The LWG estimates the overall remedial investigation and feasibility study will cost approximately $10 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study has been completed, the EPA has decided on a strategy, and a record of decision has been published. While the remedial investigation and feasibility study for the harbor site has commenced, it is expected to take several years to complete. The development of a proposed plan and record of decision on the harbor site is not anticipated to occur until 2006, after which a cleanup plan will be undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the DEQ and other information available, MBI does not believe it is a Responsible Party. In addition, MBI has notified Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, that it intends to seek indemnity for any and all liabilities incurred in relation to the above matters, pursuant to the terms of their sale agreement.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above administrative action.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2003, were $18.1 million in 2004, $12.4 million in 2005, $8.7 million in 2006, $5.1 million in 2007, $3.9 million in 2008 and $22.1 million thereafter. Rent expense was approximately $27.2 million, $26.9 million and $31.5 million for the years

ended December 31, 2003, 2002 and 2001, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation, construction materials supply and electric generation construction contracts. These commitments range from one to 21 years. The commitments under these contracts as of December 31, 2003, were $167.2 million in 2004, $67.2 million in 2005, $50.1 million in 2006, $31.0 million in 2007, $30.9 million in 20 and $146.3 million thereafter. Amounts purchased under these various commitments for th years ended December 31, 2003, 2002 and 2001, were approximately $204.6 million, $152.1 million and $193.0 million, respectively. These commitments are not reflected in the Company's consolidated financial statements.

Guarantees
Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX in connection with the Company's equity method investment in the natural gas-fired electric generating facility in Brazil, as discussed in Note 2. The Company, through MDU Brasil, owns 49 percent of MPX. The main business purpose of Centennial extending the guarantee to MPX's creditors is to enable MPX to obtain lower borrowing costs. At December 31, 2003, the aggregate amount of borrowings outstanding subject to these guarantees was $45 million and the scheduled repayment of these borrowings is $11.0 million in 2004, $10.7 million in 2005, $10.7 million in 2006, $10.7 million in 2007 and $2.4 million in 2008. The individual investor (who through EBX Empreendimentos Ltda. (EBX), a Brazilian compan owns 51 percent of MPX) has also guaranteed a portion of these loans. In the event MPX defaults under its obligation, Centennial and the individual investor would be required make payments under their guarantees. Centennial and the individual investor have enter into reimbursement agreements under which they have agreed to reimburse each other to th extent they may be required to make any guarantee payments in excess of their proportionate ownership share in MPX. These guarantees are not reflected on the Consolidated Balance Sheets.

In addition, WBI Holdings, Inc. (WBI Holdings), an indirect wholly owned subsidiary of tl Company, has guaranteed certain of its subsidiary's natural gas and oil price swap and collar agreement obligations. The amount of the subsidiary's obligations at December 31 2003, was $1.8 million. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements, as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements at December 31, 2003, expire in 200 however, the subsidiary continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. At December 31, 2003, the amount outstanding was reflected on the Consolidated Balance Sheets. In the event the above subsidiary defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company that are related to natura gas transportation and sales agreements, electric power supply agreements, insurance policies and certain other guarantees. At December 31, 2003, the fixed maximum amounts guaranteed under these agreements aggregated $46.4 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $20.1 million in 2004; $5.9 million in 2005; $3.5 million in 2006; $500,000 in 2007; $900,000 i 2009; $12.0 million in 2012; $500,000, which is subject to expiration 30 days after the receipt of written notice and $3.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $372,000 and was reflected on the Consolidated Balance Sheets at December 31, 2003. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarante the performance of Prairielands Energy Marketing, Inc. (Prairielands), an indirect wholly owned subsidiary of the Company. At December 31, 2003, the fixed maximum amounts guaranteed under these agreements aggregated $22.9 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $2.9 million in 2005 and $20. million in 2009. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was $837,000, which was not reflected on the Consolidated Balance Sheet at December 31, 2003, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial has issued guarantees related to the Company's purchase of maintenance items to third parties for which no fixed maximum amounts have been specified These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation in relation to the purchase of certain maintenance items, Centennial would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items were reflected on the Consolidated Balance Sheet at December 31, 2003.

As of December 31, 2003, Centennial was contingently liable for the performance of certai of its subsidiaries under approximately $360 million of surety bonds. These bonds are principally for construction contracts and reclamation obligations of these subsidiaries entered into in the normal course of business. Centennial indemnifies the respective surety bond companies against any exposure under the bonds. The purpose of Centennial's indemnification is to allow the subsidiaries to obtain bonding at competitive rates. In the event a subsidiary of the Company does not fulfill its obligations in relation to its bonded contract or obligation, Centennial may be required to make payments under its indemnification. A large portion of these contingent commitments are expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. The surety bonds were not reflected on the Consolidated Balance Sheets.

NOTE 20
Investment in Subsidiaries
The Respondent owns one wholly owned subsidiary, Centennial Energy Holdings, Inc.

As required by the Federal Energy Regulatory Commission for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by generally accepted accounting principles. If generally accepted accounting principles were followed, utility plant, other property and investments would increase by $583,119,019 and $440,603,661; current and accrued assets would increase by $480,874,653 and $429,117,903; deferred debits would increase by $433,317,248 and $382,761,205; preferred stock would decrease by $0 and $100,000; long-term debt would increase by $735,936,753 and $636,749,515; other noncurrent liabilities and current and accrued liabilities would increase by $202,668,975 and $208,485,102; deferred credits would increase by $562,331,004 and $410,973,964 as of December 31, 2003 and 2002, respectively. Furthermore, operating revenues would increase by $1,899,020,074 and $1,682,352,992; and operating expenses, excluding income taxes, would increase by $1,629,210,888 and $1,452,565,545 for the year ended December 31, 2003 and 2002, respectively. In addition, net cash provided by operating activities would increase by $368,926,000; net cash used ir investing activities would increase by $385,821,000; net cash used by financing activitie would decrease by $35,662,000; and the net change in cash and cash equivalents would be ar increase of $18,767,000 for the year ended December 31, 2003. Reporting its subsidiary investment using the equity method rather than generally accepted accounting principles has no effect on net income or retained earnings.

DOCKET NO.___
RULE 20:10:13:52
STATEMENT B

INDEX

Income Statement	Page Nos.
Twelve months ended December 31, 2003	1 - 2
Twelve months ended March 31, 2004	3 - 4

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2003

Operating Income	
Electric Utility	
Operating Revenues	$178,561,980
Operating Expenses:	
Operation Expenses	101,790,710
Maintenance Expenses	13,176,267
Depreciation Expenses	20,150,400
Taxes Other Than Income Taxes	7,683,325
Income Taxes:	
Federal Taxes on Income	7,844,316
State Taxes on Income	1,381,596
Deferred Income Taxes	1,383,686
Total Electric Expenses	153,410,300
Net Electric Operation	$25,151,680
Gas Utility	
Operating Revenues	$274,607,103
Operating Expenses:	
Operation Expenses	250,033,668
Maintenance Expenses	2,792,254
Depreciation Expenses	10,044,705
Taxes Other Than Income Taxes	5,234,669
Income Taxes:	
Federal Taxes on Income	(3,267,639)
State Taxes on Income	(564,828)
Deferred Income Taxes	4,510,834
Total Gas Expenses	268,783,663
Net Gas Operation	$5,823,440
Net Utility Operating Income	$30,975,120
Revenues from Merchandising, Jobbing and Contract Work	$12,638,073
(Less) Costs and Exp. Of Merch., Jobbing and Contract Work	11,055,815
Revenues from Nonutility Operations	211,102
Equity in Earnings of Subsidiary Companies	153,788,920
Interest and Dividend Income	3,636,870
Miscellaneous Nonoperating Income	743
Gain on Disposition of Property	54,123
Total Other Income	159,274,016
Loss on Disposition of Property	9,749
Miscellaneous Income Deductions	2,564,974
Total Other Income Deductions	2,574,723

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2003

Taxes other than Income Taxes	5,120
Income Taxes - Federal	1,377,137
Income Taxes - State	221,809
Provision for Deferred Income Taxes	(606,763)
Investment Tax Credits	(596,333)
Total Taxes on Other Income and Deductions	400,970
Net Other Income and Deductions	$156,298,323
Interest On Long-Term Debt	10,629,946
Amortization of Debt Discount and Expense	1,252,461
Other Interest Expense	250,711
(Less) Allow for Borrowed Funds Used during Const.	217,797
Net Interest Charges	11,915,321
Net Income	$175,358,122

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING MARCH 31, 2004

Operating Income	
Electric Utility	
Operating Revenues	$46,989,060
Operating Expenses:	
Operation Expenses	29,050,809
Maintenance Expenses	2,671,795
Depreciation Expenses	5,010,957
Taxes Other Than Income Taxes	2,212,650
Income Taxes:	
Federal Taxes on Income	1,723,789
State Taxes on Income	447,213
Deferred Income Taxes	7,806
Total Electric Expenses	41,125,019
Net Electric Operation	$5,864,041
Gas Utility	
Operating Revenues	$128,318,554
Operating Expenses:	
Operation Expenses	118,625,973
Maintenance Expenses	767,262
Depreciation Expenses	2,344,767
Taxes Other Than Income Taxes	1,581,040
Income Taxes:	
Federal Taxes on Income	3,824,941
State Taxes on Income	740,590
Deferred Income Taxes	(3,088,915)
Total Gas Expenses	124,795,658
Net Gas Operation	$3,522,896
Net Utility Operating Income	$9,386,937
Revenues from Merchandising, Jobbing and Contract Work	$2,480,598
(Less) Costs and Exp. Of Merch., Jobbing and Contract Work	3,293,856
Revenues from Nonutility Operations	195,546
(Less) Expense from Nonutility Operations	83,095
Equity in Earnings of Subsidiary Companies	17,676,925
Interest and Dividend Income	1,112,499
Miscellaneous Nonoperating Income	0
Gain on Disposition of Property	0
Total Other Income	18,088,617
Loss on Disposition of Property	6,665
Miscellaneous Income Deductions	781,812
Total Other Income Deductions	788,477

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING MARCH 31, 2004

Taxes other than Income Taxes	16,294
Income Taxes - Federal	55,078
Income Taxes - State	(2,041)
Provision for Deferred Income Taxes	(188,307)
Investment Tax Credits	(141,909)
Total Taxes on Other Income and Deductions	(260,885)
Net Other Income and Deductions	$17,561,025
Interest On Long-Term Debt	3,036,615
Amortization of Debt Discount and Expense	39,774
Amortization of Loss on Reacquired Debt	253,927
Other Interest Expense	67,917
(Less) Allow for Borrowed Funds Used during Const.	29,894
Net Interest Charges	3,368,339
Net Income	$23,579,623

MDU RESOURCES GROUP, INC.
STATEMENT OF RETAINED EARNINGS
DECEMBER 31, 2003

Retained Earnings at December 31, 2002		$44,231,211
Unappropriated Undistributed Subsidiary Earnings at December 31, 2002		430,566,718
Retained Earnings at December 31, 2002		474,797,929
Net Income from Income Statement for the Twelve Months ended December 31, 2003		175,358,122
Dividend Appropriation of Surplus:		
4.50% Preferred Stock	$450,005	
4.70% Preferred Stock	235,000	
5.10% Preferred Stock	66,300	
Common Stock	74,118,558	74,869,863
Retained Earnings at December 31, 2003		$575,286,188

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT A

Function	Balance @ 12/31/02	Balance @ 12/31/03	Average Balance @ 12/31/03	Additions to Plant 1/	Pro Forma Balance @ 12/31/04	Average Balance @ 12/31/04	Pro Forma Adjustment
Distribution	$30,913,008	$32,800,336	$31,856,672	$2,090,077	$34,890,413	$33,845,375	$1,988,703
General	9,419,101	9,147,882	9,283,492	508,218	9,656,100	9,401,991	118,499
General Intangible	135,079	138,705	136,892		138,705	138,705	1,813
Common	1,187,656	1,455,027	1,321,341	128,079	1,583,106	1,519,067	197,726
Common Intangible	1,073,230	1,240,928	1,157,079	229,981	1,470,909	1,355,918	198,839
Construction Work in Progress (CWIP) in Service not yet Classified 2/		324,862	324,862		324,862	324,862	
Total	$42,728,074	$45,107,740	$44,080,338	$2,956,355	$48,064,095	$46,585,918	$2,505,580

1/ See Rule 20:10:13:56, Statement D.
2/ CWIP in Service is reflected at the year end balance.

DOCKET NO. _____
RULE 20:10:13:54
STATEMENT D
PAGE 1 OF 4

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT A

Acct. No.	Account	Balance @ 12/31/02	Balance @ 12/31/03	Average Balance @ 12/31/03	Pro Forma Adjustments to Plant 1/	Pro Forma Balance @ 12/31/04	Average Balance @ 12/31/04	Pro Forma Adjustment
	Distribution Plant							
374.1	Land	$30,306	$29,922	$30,114		$29,922	$29,922	($192)
374.2	Rights of Way	8,609	8,609	8,609		8,609	8,609	
375	Structures & Improvements	37,325	39,785	38,555		39,785	39,785	1,230
376	Mains	17,929,972	19,047,110	18,488,541	$1,491,864	20,538,974	19,793,042	1,304,501
378	Meas. & Reg. Equip.-General	243,979	258,883	251,431	65,301	324,184	291,533	40,102
379	Meas. & Reg. Equip.-City Gate	58,623	78,548	68,586		78,548	78,548	9,962
380	Services	5,377,654	5,738,455	5,558,054	241,031	5,979,486	5,858,971	300,917
381	Positive Meters	5,998,919	6,327,447	6,163,183	241,264	6,568,711	6,448,079	284,896
383	Service Regulators	840,674	884,630	862,652	35,607	920,237	902,434	39,782
385	Ind. Meas. & Reg. Station Eqpt.	63,429	63,429	63,429		63,429	63,429	
386.2	Other Property on Cust. Premise	170,931	170,931	170,931		170,931	170,931	
387.1	Cathodic Protection Equip.	66,245	66,245	66,245	15,010	81,255	73,750	7,505
387.2	Other Distribution Equip.	86,342	86,342	86,342		86,342	86,342	
	Total Distribution Plant	$30,913,008	$32,800,336	$31,856,672	$2,090,077	$34,890,413	$33,845,375	$1,988,703
	General Plant							
389	Land	$582,013	$580,983	$581,498		$580,983	$580,983	(515)
390	Structures and Improvements	3,775,980	3,769,782	3,772,881		3,769,782	3,769,782	($3,099)
391.1	Furniture and Fixtures	364,448	226,766	295,607	$6,234	233,000	229,883	(65,724)
391.3	Computer Equip. - PC	237,293	255,293	246,293	1,541	256,834	256,064	9,771
392.1	Trans. Equip., Non-Unitized	35,860	35,859	35,860		35,859	35,859	(1)
392.2	Trans. Equip., Unitized	1,910,571	1,849,562	1,880,067	288,794	2,138,356	1,993,959	113,892
393	Stores Equipment	56,721	45,724	51,222		45,724	45,724	(5,498)
394.1	Tools,Shop&Gar. Eq.-Non-Un.	520,410	346,507	433,458	21,751	368,258	357,382	(76,076)
394.2	Tools,Shop&Gar. Eq.-Unitized	57,875	24,072	40,974		24,072	24,072	(16,902)
394.3	Vehicle Maintenance Equip.	7,627	7,627	7,627		7,627	7,627	
394.4	Vehicle Refueling Equip.	138,079	66,386	102,233		66,386	66,386	(35,847)
395	Laboratory Equipment	42,947	19,588	31,268		19,588	19,588	(11,680)

DOCKET NO. ____
RULE 20:10:13:5
STATEMENT D
PAGE 2 OF 4

MONTANA-DAKOTA UTILITIES CO.
PLANT SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT A

Acct. No.	Account	Balance @ 12/31/02	Balance @ 12/31/03	Average Balance @ 12/31/03	Pro Forma Adjustments to Plant 1/	Pro Forma Balance @ 12/31/04	Average Balance @ 12/31/04	Pro Forma Adjustment
396.1	Power Operated Equip.	96,572	96,572	96,572	174,319	270,891	183,732	87,160
396.2	Work Equipment Trailers	1,184,412	1,540,151	1,362,281		1,540,151	1,540,151	177,870
397.1	Radio Comm. Equip.-Fixed	97,627	97,627	97,627	15,579	113,206	105,416	7,789
397.2	Radio Comm. Equip.-Mobile	125,394	126,620	126,007		126,620	126,620	613
397.3	General Tele. Comm. Equip.	47,773	25,321	36,547		25,321	25,321	(11,226)
397.5	Supervisory & Tele. Equip.	84,779		42,389				(42,389)
397.6	Scada System	770		385				(385)
397.8	Network Equipment	18,671	23,831	21,251		23,831	23,831	2,580
398	Miscellaneous Equipment	33,279	9,611	21,445		9,611	9,611	(11,834)
	Total General Plant	$9,419,101	$9,147,882	9,283,492	$508,218	$9,656,100	$9,401,991	$118,499
303	Intangible Plant - General	$135,079	$138,705	$136,892		$138,705	$138,705	$1,813
	Common Plant							
389	Land	$31,426	$35,977	$33,701		$35,977	$35,977	$2,276
390	Structures and Improvements	390,451	462,432	426,442	$14,477	476,909	469,671	43,229
391.1	Furniture and Fixtures	160,910	123,640	142,275	12,504	136,144	129,892	(12,383)
391.2	Computer Equip.- Bull/AS400	6,671	1,218	3,945		1,218	1,218	(2,727)
391.3	Computer Equip. - PC	226,938	242,574	234,756	69,544	312,118	277,345	42,589
391.4	Computer Equip. - Other (EMS)	388	450	419		450	450	31
391.5	Computer Equip. - Other	58,283	5,312	31,797	3,827	9,139	7,226	(24,571)
392.1	Trans. Equip., Non-Unitized	1,639	1,870	1,754		1,870	1,870	116
392.2	Trans. Equip., Unitized	56,235	55,331	55,783	15,397	70,728	63,030	7,247
392.3	Aircraft	77,196	377,806	227,501		377,806	377,806	150,305
393	Stores Equipment	283	323	303		323	323	20
394.1	Tools, Shop & Gar. Equip.	1,993	2,285	2,139		2,285	2,285	146
394.3	Vehicle Maint. Equip.	6,103	7,850	6,976		7,850	7,850	874
394.4	Vehicle Refueling Equip.	6,848	8,388	7,618		8,388	8,388	770
396.2	Work Equipment Trailers	3,697		1,849				(1,849)

DOCKET NO. _____
RULE 20:10:13:5
STATEMENT D
PAGE 3 OF 4

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT A

Acct. No.	Account	Balance @ 12/31/02	Balance @ 12/31/03	Average Balance @ 12/31/03	Pro Forma Adjustments to Plant 1/	Pro Forma Balance @ 12/31/04	Average Balance @ 12/31/04	Pro Forma Adjustment
397.1	Radio Comm. Equip.-Fixed	13,559	10,645	12,102	5,952	16,597	13,621	1,519
397.2	Radio Comm. Equip.-Mobile	18,072	21,960	20,016		21,960	21,960	1,944
397.3	General Tele. Comm. Equip.	28,933	32,994	30,964		32,994	32,994	2,030
397.5	Supervisory & Tele. Equip.	156	179	167		179	179	12
397.8	Network Equipment	66,646	28,388	47,517	6,378	34,766	31,577	(15,940)
398	Miscellaneous Equipment	31,229	35,405	33,317		35,405	35,405	2,088
	Total Common Plant	$1,187,656	$1,455,027	$1,321,341	$128,079	$1,583,106	$1,519,067	$197,726
303	Intangible Plant - Common	$1,073,230	$1,240,928	$1,157,079	$229,981	$1,470,909	$1,355,918	$198,839
	Total Gas Plant in Service	$42,728,074	$44,782,878	$43,755,476	$2,956,355	$47,739,233	$46,261,056	$2,505,580

1/ See Rule 20:10:13:56, Statement D.

DOCKET NO. _____
RULE 20:10:13:54
STATEMENT D
PAGE 4 OF 4

MONTANA-DAKOTA UTILITIES CO.
DETAILED COST OF PLANT
GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Acct. No.	Account	Balance @ 12/31/02	Additions	Retirements	Transfers	Balance @ 12/31/03
	Distribution Plant					
374.1	Land	$109,547	$0	($384)	($312)	$108,851
374.2	Rights of Way	95,588	1,496	(65)	0	97,019
375	Structures & Improvements	521,210	10,178	(450)	0	530,938
376	Mains	80,182,712	3,785,387	(234,006)	0	83,734,093
378	Measuring & Regulating Equip. - Gen.	1,423,150	45,097	(10,744)	0	1,457,503
379	Measuring & Regulating Equip. - City Gate	1,009,137	23,172	(4,388)	0	1,027,921
380	Services	33,733,349	2,103,050	(163,649)	0	35,672,750
381	Meters	32,113,684	1,433,811	(13,398)	0	33,534,097
383	Service Regulators	4,402,528	208,127	(11,656)	0	4,598,999
385	Industrial Measuring & Regulating Equip.	578,786	55,439	(6,164)	0	628,061
386.1	Misc. Property on Customer Premise	1,680	0	0	0	1,680
386.2	Other Property on Customer Premise	432,812	0	0	0	432,812
387.1	Cathodic Protection Equipment	1,476,915	44,534	(5,054)	0	1,516,395
387.2	Other Distribution Equipment	557,184	1,415	(1,945)	0	556,654
	Total Distribution Plant	$156,638,282	$7,711,706	($451,903)	($312)	$163,897,773
	General Plant					
389	Land	$851,350	($107)	$0	$312	$851,555
390	Structures & Improvements	5,689,188	22,040	(9,314)	0	5,701,914
391.1	Office Furniture & Equipment	755,201	18,121	(404,720)	3,483	372,085
391.3	Computer Equip.-PC	786,659	244,662	(57,519)	0	973,802
392.1	Transportation Equipment - Non-Un.	155,417	16,065	0	0	171,482
392.2	Transportation Equipment - Unitized	6,457,020	902,779	(551,428)	103,664	6,912,035
393	Stores Equipment	192,629	14,254	(63,868)	0	143,015
394.1	Tools,Shop&Gar. Equip.-Non-Un.	2,610,721	144,680	(1,286,765)	0	1,468,636
394.2	Tools,Shop&Gar. Equip.-Non-Un.	299,810	0	(193,745)	0	106,065
394.3	Vehicle Maintenance Equipment	31,177	0	0	0	31,177
394.4	Vehicle Refueling Equipment	361,344	0	(168,497)	0	192,847
395	Laboratory Equipment	324,158	0	(111,337)	0	212,821

DOCKET NO. _____
RULE 20:10:13:55
STATEMENT D
SCHEDULE D-1
PAGE 1 OF 2

MONTANA-DAKOTA UTILITIES CO.
DETAILED COST OF PLANT
GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Acct. No.	Account	Balance @ 12/31/02	Additions	Retirements	Transfers	Balance @ 12/31/03
396.1	Work Equipment Trailers	359,619	0	(5,323)	0	354,296
396.2	Power Operated Equipment	4,120,765	1,718,894	(1,487,415)	136,299	4,488,543
397.1	Radio Communication Equip. - Fixed	482,215	0	27,488	0	509,703
397.2	Radio Communication Equip. - Mobile	413,977	1,226	1,427	0	416,630
397.3	General Tele. Comm. Equip.	101,422	0	(58,268)	0	43,154
397.5	Supervisory & Tele. Equip.	124,167	0	(123,043)	0	1,124
397.6	Scada System	30,894	0	(30,894)	0	0
397.8	Network Equipment	31,698	7,899	0	(308)	39,289
398	Miscellaneous Equipment	147,510	542	(101,445)	0	46,607
	Total General Plant	$24,326,941	$3,091,055	($4,624,666)	$243,450	$23,036,780
303	General Intangible	477,530	0	0	0	477,530
	Common Plant - Gas 1/	19,155,659				19,728,338
	Gas Plant Leased to Others					
386.3	CNG Demo/Lease	25,773	0	0	0	25,773
114.3	Acquisition Adjustments	97,266	0	0	0	97,266
	Total Gas Plant in Service	$200,721,451	$10,802,761	($5,076,569)	$243,138	$207,263,460

1/ Common plant is either directly assigned or allocated to gas and electric plant. Total common plant additions, retirements, transfers and adjustments for the twelve months ended December 31, 2003 are $6,361,627, $5,558,638, and ($790,319) respectively.

DOCKET NO. _____
RULE 20:10:13:55
STATEMENT D
SCHEDULE D-1
PAGE 2 OF 2

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 2003

Work Order #	Description	Location	Construction Period	Date Placed In-Service	Beginning Balance	Major Additions	Major Retirements	Transfers	Ending Balance
	Gas Plant				$181,442,752				
J131204	Relocate gas main on Omaha St., Rapid City	SD	7/22/02-1/31/03	01/31/03		$380,352			
J138318	Upgrade IP system of East Bismarck	ND	1/15/03-7/31/03	7/31/03		359,567			
J133092	Replace bare unprotected main, Billings	MT	5/5/03-12/8/03	12/8/03		198,639			
J143282	Gas main extension at Hidden Lake Sub, Billings	MT	3/27/03-12/15/03	12/15/2003		178,365			
J119404	Install Main, Billings	MT	4/25/03-5/23/03	5/23/2003		175,854			
J142889	Extend gas main in SE Minot	ND	7/13/03-11/16/03	11/16/2003		141,773			
J128484	Extend gas main - Copper Oaks, Rapid City	SD	7/1/02-6/30/03	6/30/2003		130,848			
	Major projects Subtotal				181,442,752	1,565,398	0	0	
	Miscellaneous Projects					9,237,361	5,076,567	243,138	
	Subtotal				181,442,752	10,802,759	5,076,567	243,138	187,412,082
	Common Plant Allocated to Gas				19,155,660				19,728,338
	Gas Plant Leased to Others				25,773				25,773
	Total Gas Plant				$200,624,185				$207,166,193

DOCKET NO. _____
RULE 20:10:13:56
STATEMENT D
SCHEDULE D-2
PAGE 1 OF 4

MONTANA-DAKOTA UTILITIES CO.
GAS CWIP IN SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Work Order Number	Description	State	Total	Distribution	General	Common
J131204	Omaha Street Relocation	SD	($9,035)	($9,035)		
J136907	Replace Conquest aircraft	ND	(928)			($928)
J141071	Reconstruct Transportation Dept. Bldg.	SD	(333)			(333)
J143593	Remodel Annex Building	ND	(22)			(22)
	Small items grouped 1/:					
(36)	Distribution	SD	291,747	291,747		
(10)	General	SD	40,065		$40,065	
(36)	Common	ND	3,359			3,359
	Total		$324,862	$282,721	$40,065	$2,076

1/ Numbers in brackets indicate the number of work orders involved in each item of construction.

MONTANA-DAKOTA UTILITIES CO.
PLANT ADDITIONS - SUMMARY
GAS UTILITY - SOUTH DAKOTA
PRO FORMA 2004

Acct. #	Project No.	Description	Region	Amount
		Distribution		
376	B13430G	Mains - Black Hills - Growth	Black Hills	$682,320
376	B13430R	Mains - Black Hills - Replace	Black Hills	223,329
376	J144199	Relocate 8" and 4" Gas Main	Black Hills	40,146
376	J144208	Relocate 4" Gas Main 79th Street	Black Hills	28,431
376	J148622	Install Main Elk Vale Road Project	Black Hills	450,643
376	J149302	Install 4" Gas Main Elk Vale Road Project	Black Hills	66,995
378	B13434	Measuring & Regulators	Black Hills	22,540
378	B900034	Measuring & Regulating Equipment	General Office	1,073
378	J149325	Regulator Station - Elk Vale Road Project	Black Hills	24,686
378	J149326	Regulator Station - Homestead and Elk Vale	Black Hills	17,002
380	B13433	Service Lines	Black Hills	241,031
381	B90031	Meters	General Office	218,465
381	J144408	Install Gas Meter Read ERTs	Dakota Heartlar	22,799
383	B90032	Regulators	General Office	35,607
387.1	B13435	Cathodic Protection	Black Hills	15,010
		Total Distribution		2,090,077
		General		
391.1	B13442	Office Equipment	Black Hills	6,234
391.3	B13440	Personal Computers	Black Hills	1,541
392.2	B13438	Vehicles	Black Hills	288,794
394.1	B13443	Minor Work Equipment	Black Hills	20,771
394.1	B90043	Minor Work Equipment	General Office	980
396.1	B13439	Work Equipment	Black Hills	174,319
397.1	B13444	Communication Equipment	Black Hills	15,579
		Total General		508,218
		Common		
390	J76814	Remodel costs for Annex	General Office	2,035
390	J144913	Install Multi-Stack Modular Chiller	General Office	12,442
391.1	B90082	Office Equipment	General Office	11,399
391.1	J144173	Purchase 4 Workstations	General Office	1,105
391.3	B90080	Personal Computers	General Office	40,865
391.3	J133994	Purchase Imaging System	General Office	14,414
391.3	J144522	Purchase 30 Repl MDTs Per Year - MobileUp	General Office	14,265
391.5	J120082	Purchase Bar Coding Equip - MobileUp	General Office	3,827
392.2	B90078	Vehicles	General Office	15,397
397.1	B90084	Communication Equipment	General Office	5,952
397.8	B90081	Network Equipment	General Office	6,378
		Total Common		128,079
		Common - Intangible		
303	J61813	GIS (GEMS) Project	General Office	120,128
303	J144387	Upgrade MUP To Version 6	General Office	22,109
303	J144635	Upgrade Financial Forecast/Budget System	General Office	42,677
303	J144879	Implement JDE One World	General Office	45,067
		Common Intangible		229,981
				$2,956,355

MONTANA-DAKOTA UTILITIES CO.
PLANT ADDITIONS - SUMMARY
GAS UTILITY - SOUTH DAKOTA
PRO FORMA 2004

Distribution	$2,090,077
General	
Other	23,354
Transportation	288,794
Work Equipment	174,319
Tools	21,751
Common	
Other	112,682
Transportation	15,397
Intangible	229,981
Total Additions	$2,956,355

MONTANA-DAKOTA UTILITIES CO.
AVERAGE ALLOCATED GAS PLANT IN SERVICE BALANCES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Acct. No.	Account	January Average	February Average	March Average	April Average	May Average	June Average	July Average	August Average	September Average	October Average	November Average	December Average	12 Months Average
	Distribution Plant													
374.1	Land	$30,306	$30,306	$30,306	$30,306	$30,306	$30,306	$30,114	$29,922	$29,922	$29,922	$29,922	$29,922	$30,130
374.2	Rights of Way	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609
375	Structures & Improvements	37,325	37,325	37,325	37,325	37,325	37,325	37,325	38,219	39,449	39,785	39,785	39,785	38,192
376	Mains	18,008,451	18,149,872	18,227,215	18,251,281	18,275,044	18,295,251	18,540,127	18,793,760	18,873,333	18,931,076	18,922,738	18,984,237	18,521,032
378	Meas & Reg Equip-General	243,979	243,979	243,979	243,979	248,260	252,541	252,541	254,397	256,975	257,697	257,697	258,290	251,193
379	Meas & Reg Equip-City Gate	58,623	58,623	58,623	58,623	58,623	58,623	68,086	78,048	78,548	78,548	78,548	78,548	67,672
380	Services	5,400,488	5,426,346	5,446,056	5,469,236	5,481,700	5,495,704	5,525,996	5,559,978	5,605,758	5,635,889	5,631,965	5,685,210	5,530,361
381	Positive Meters	6,029,063	6,061,475	6,076,051	6,102,785	6,123,772	6,152,038	6,187,280	6,208,418	6,251,726	6,287,434	6,293,970	6,313,976	6,173,999
383	Service Regulators	845,653	854,344	857,491	857,848	860,156	862,913	866,204	870,349	875,516	878,458	880,652	883,738	866,110
385	Ind Meas & Reg Sta Eqpt	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429
386	Other Property on Cust. Premise	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931
387.1	Cathodic Protection Equip.	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245
387.2	Other Distribution Equip.	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342
	Total Distribution Plant	$31,049,444	$31,257,826	$31,372,602	$31,446,939	$31,510,742	$31,580,257	$31,903,229	$32,228,647	$32,406,783	$32,534,365	$32,530,833	$32,669,262	$31,874,245
	General Plant													
389	Land	$581,545	$581,076	$581,030	$580,983	$580,983	$580,983	$580,983	$580,983	$580,983	$580,983	$580,983	$580,983	$581,042
390	Structures and Improvements	3,773,199	3,770,417	3,770,100	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,770,146
391	Furniture & Fixtures	340,735	317,021	317,146	317,270	317,270	317,270	317,270	317,270	272,018	226,766	226,766	226,766	292,797
391	Computer Equip.-PC	225,789	214,285	215,290	220,649	226,101	226,680	226,161	228,844	243,410	255,293	255,293	255,293	232,757
392.1	Transportation Equip, Non-Un.	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859
392	Transportation Equip, Unitized	1,855,483	1,810,736	1,821,260	1,821,044	1,803,191	1,777,510	1,748,432	1,702,229	1,676,878	1,665,613	1,654,348	1,751,955	1,757,390
393	Stores Equipment	56,721	56,721	56,721	56,721	56,721	56,721	56,721	56,721	51,223	45,724	45,724	45,724	53,514
394.1	Tools,Shop&Gar. Equip.-Non-Un.	522,230	524,050	524,050	524,050	524,050	536,637	549,223	549,223	443,149	339,726	342,376	344,442	476,934
394.2	Tools,Shop&Gar. Equip.-Unitized	57,875	57,875	57,875	57,875	57,875	57,875	57,875	57,875	40,974	24,072	24,072	24,072	48,016
394.3	Vehicle Maintenance Equip.	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627
394.4	Vehicle Refueling Equip.	138,079	138,079	138,079	138,079	138,079	138,079	138,079	138,079	102,233	66,386	66,386	66,386	117,169
395	Laboratory Equipment	42,971	42,995	42,995	42,995	42,995	42,995	42,995	42,995	31,292	19,588	19,588	19,588	36,166
396	Power Operated Equip.	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572
396	Work Equipment Trailers	1,165,607	1,182,165	1,196,898	1,190,956	1,210,055	1,358,916	1,484,861	1,486,988	1,529,170	1,550,268	1,529,184	1,534,668	1,368,311
397.1	Radio Comm. Equip.-Fixed	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627
397.2	Radio Comm. Equip.-Mobile	125,394	125,394	125,749	126,362	126,620	126,620	126,620	126,620	126,620	126,620	126,620	126,620	126,322
397.3	General Tele. Comm. Equip.	47,773	47,773	47,773	47,773	47,773	47,773	47,773	47,773	36,547	25,321	25,321	25,321	41,225
397.5	Supervisory & Tele. Equip.	84,829	84,878	84,878	84,878	84,878	84,878	84,878	84,878	42,439	-	-	-	60,118
397.6	Scada System	770	770	770	770	770	770	770	770	385	-	-	-	545
397.8	Network Equipment	18,671	20,514	22,356	22,356	22,356	22,356	22,356	22,356	23,094	23,831	23,831	23,831	22,326
398	Miscellaneous Equipment	33,314	33,349	33,349	33,349	33,349	33,349	33,349	33,349	21,209	9,069	9,069	9,340	26,287
	Total General Plant	$9,308,670	$9,245,783	$9,274,004	$9,273,577	$9,280,533	$9,416,879	$9,525,813	$9,484,420	$9,229,091	$8,966,727	$8,937,028	$9,042,456	$9,248,750
303	Intangible Plant - General	$136,892	$138,705	138,705	$138,705	$138,705	$138,705	$138,705	$138,705	$138,705	$138,705	$138,705	$138,705	$138,554

DOCKET NO.
RULE 20:10:13:
STATEMENT D
SCHEDULE D-3
PAGE 1 OF 2

MONTANA-DAKOTA UTILITIES CO.
AVERAGE ALLOCATED GAS PLANT IN SERVICE BALANCES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Acct. No.	Account	January Average	February Average	March Average	April Average	May Average	June Average	July Average	August Average	September Average	October Average	November Average	December Average	12 Months Average
	Common Plant													
389	Land	$33,702	$35,977	$35,977	$35,977	$35,977	$35,977	$35,977	$35,977	$35,977	$35,977	$35,977	$35,977	$35,787
390	Structures and Improvements	418,899	447,346	447,346	447,346	447,346	447,346	447,346	447,346	449,356	451,366	451,362	456,895	446,608
391	Furniture & Fixtures	172,832	185,092	185,060	184,755	184,809	184,412	184,026	184,405	153,438	122,092	122,092	122,866	165,490
391	Computer Equipment-Bull/AS400	7,159	7,646	7,646	7,646	7,646	7,646	7,646	7,646	4,432	1,218	1,218	1,218	5,731
391	Computer Equip.-PC	230,392	234,084	235,240	238,890	242,097	243,586	244,600	245,850	242,778	238,456	238,456	240,515	239,579
391	Computer Equip. - Other (EMS)	419	450	450	450	450	450	450	450	450	450	450	450	447
392	Computer Equip.-Other	62,543	66,802	66,802	66,802	66,802	66,895	66,988	66,988	35,755	4,522	4,522	4,917	48,362
392.1	Trans. Equip., Non-Unitized	1,755	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,860
392.2	Trans. Equip., Unitized	60,534	63,357	63,282	64,328	63,244	58,897	55,277	56,637	58,293	58,589	57,436	55,807	59,640
392.3	Aircraft	82,838	222,563	356,645	356,645	363,767	370,888	370,888	370,888	374,347	377,806	377,806	377,806	333,574
393	Stores Equip.	303	323	323	323	323	323	323	323	323	323	323	323	321
394	Tools, Shop and Garage Equip.	2,140	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,273
394.3	Vehicle Maint. Equip.	6,532	6,960	7,057	7,153	7,153	7,153	7,153	7,502	7,850	7,850	7,850	7,850	7,339
394.4	Vehicle Refueling Equip.	7,618	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,324
396	Work Equipment Trailers	3,957	4,217	4,217	4,217	4,217	4,217	4,217	2,109	-	-	-	-	2,614
397.1	Radio Comm. Equip.-Fixed	14,550	15,541	15,541	15,541	15,541	15,541	15,541	15,541	13,093	10,645	10,645	10,645	14,030
397.2	Radio Comm. Equip.-Mobile	19,393	20,714	20,714	20,714	21,337	21,960	21,960	21,960	21,960	21,960	21,960	21,960	21,383
397.3	General Tele. Comm. Equip.	30,927	32,920	32,920	32,832	32,918	33,733	34,372	35,166	34,346	32,733	32,733	32,864	33,205
397.5	Supervisory & Tele. Equip.	168	179	179	179	179	179	179	179	179	179	179	179	178
397.8	Network Equipment	71,564	76,402	76,488	77,520	78,456	55,858	33,190	33,190	30,364	27,537	27,537	27,963	51,339
398	Miscellaneous Equipment	33,510	35,790	35,790	35,790	35,790	35,790	35,790	35,830	35,287	34,704	34,704	35,055	35,319
	Total Common Plant	$1,261,735	$1,468,906	$1,604,220	$1,609,651	$1,620,595	$1,603,394	$1,578,466	$1,580,530	$1,510,771	$1,438,950	$1,437,793	$1,445,833	$1,513,403
303	Intangible Plant - Common	$1,149,678	$1,227,730	$1,229,334	$1,229,334	$1,229,333	$1,229,331	$1,229,331	$1,229,331	$1,235,050	$1,240,768	$1,240,768	$1,240,848	$1,225,903
	Total Gas Plant in Service	$42,906,419	$43,338,950	$43,618,865	$43,698,206	$43,779,908	$43,968,566	$44,375,544	$44,661,633	$44,520,400	$44,319,515	$44,285,127	$44,537,104	$44,000,855

DOCKET NO. RULE 20:10:13:57
STATEMENT D
SCHEDULE D-3
PAGE 2 OF 2

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 2002

Work Order #	Description	Location	Construction Period	Date Placed In Service	Beginning Balance	Major Additions	Major Retirements	Transfers	Ending Balance
					171,266,389				
J93941	Construct Office/Service Ctr., Rapid City	SD	12/15/00-1/28/02	1/28/2002		4,110,375			
J101500	Remediate Old Gas Plant Site, Rapid City	SD	2/29/00-1/28/02	1/28/2002		629,733			
J131204	Replace Main Omaha St., Rapid City	SD	7/22/02-1/31/03	1/31/2003		232,090			
J106177	Purchase Office Furniture/Equip., Rapid City	SD	10/1/01-5/9/02	5/9/2002		216,693			
J119794	Install 6" Main-Northeast Bismarck	ND	5/28/02-7/29/02	7/29/2002		171,073			
J119413	Replace Low Pressure Main - Billings	MT	6/12/02-7/23/03	7/23/2003		120,935			
	Major Projects Subtotal				171,266,389	5,480,899	0	0	
	Miscellaneous Projects					6,233,933	1,568,748	30,281	
	Subtotal				171,266,389	11,714,832	1,568,748	30,281	181,442,754
	Common Plant Allocated to Gas				17,624,825				19,155,660
	Gas Plant Leased To Others				25,773				25,773
	Total Gas Plant				188,916,987				200,624,187

DOCKET NO. _____
RULE 20:10:13:58
STATEMENT D
SCHEDULE D-4
PAGE 1 OF 4

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 2001

Work Order #	Description	Location	Construction Period	Date Placed In-Service	Beginning Balance	Major Additions	Major Retirements	Ending Balance	
	Gas Plant				$166,096,899				
J114001	Replace low pressure main	MT	5/23/01-11/28/01	11/23/01		$117,505			
J111910	Replace main on Highway 12 rebuild	MT	5/15/01-7/27/01	7/27/01		101,239			
J104363	Extend main to serve several new subdivisions	WY	11/2/00-12/29/00	12/29/00		152,164			
	Major projects Subtotal				166,096,899	370,908	0		
	Miscellaneous Projects					7,536,312	2,737,730		
	Subtotal				166,096,899	7,907,220	2,737,730	171,266,389	
	Common Plant Allocated to Gas				18,300,687			17,624,824	1/
	Gas Plant Leased to Others				29,961		4,188	25,773	
	Total Gas Plant				$184,427,547			$188,916,986	

1/ Includes $2,111,160 retirement for sale of Schuchart Building.

DOCKET NO. _____
RULE 20:10:13:58
STATEMENT D
SCHEDULE D-4
PAGE 2 OF 4

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 2000

Work Order #	Description	Location	Construction Period	Date Placed In Service	Beginning Balance	Major Additions	Major Retirements	Transfers	Ending Balance
					160,498,750				
J104363	Extend Main in Big Horn, Wyoming	WY	6/15/00-12/29/00	12/29/2000		167,613			
J103818	Relocate Main Rimrock Rd, Billing, MT	MT	6/13/00-11/20/00	11/20/2000		102,592			
J92036	Extend 6" Main IP Loop, Bismarck, ND	ND	8/9/00-9/5/00	9/5/2000		89,772			
J93301	Replace 8" Main Shiloh Rd, West Billings	MT	10/26/00-12/22/00	12/22/2000		78,159			
J92628	Install Main South of Sturgis	SD	8/2/99-2/20/00	2/20/2000		75,894			
	Major Projects Subtotal				160,498,750	514,030	0	0	
	Miscellaneous Projects					6,483,199	1,973,305	574,225	
	Subtotal				160,498,750	6,997,229	1,973,305	574,225	166,096,899
	Common Plant Allocated to Gas				17,941,936				18,300,687
	Gas Plant Leased To Others				29,961				29,961
	Total Gas Plant				178,470,647				184,427,547

DOCKET NO. _____
RULE 20:10:13:58
STATEMENT D
SCHEDULE D-4
PAGE 3 OF 4

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 1999

Work Order #	Description	Location	Construction Period	Date Placed In Service	Beginning Balance	Major Additions	Major Retirements	Transfers	Ending Balance
					156,229,467				
J61355	Replace Low Pressure Main, Billings	MT	1/25/99-12/31/99	12/31/1999		241,529			
J61851	Construct IP Loop Line, Rapid City	SD	4/29/99-6/25/99	6/25/1999		228,390			
J76879	Extend Main, Belle Fouche	SD	5/3/99-9/1/99	9/1/1999		91,075			
	Major Projects Subtotal				156,229,467	560,994	0	0	
	Miscellaneous Projects					6,355,947	2,597,597	(50,061)	
	Subtotal				156,229,467	6,916,941	2,597,597	(50,061)	160,498,750
	Common Plant Allocated to Gas				16,133,237				17,941,936
	Gas Plant Leased To Others				29,961				29,961
	Total Gas Plant				172,392,665				178,470,647

DOCKET NO. _____
RULE 20:10:13:58
STATEMENT D
SCHEDULE D-4
PAGE 4 OF 4

MONTANA-DAKOTA UTILITIES CO.
METHODS AND PROCEDURES FOLLOWED IN CAPITALIZING THE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION AND OTHER CONSTRUCTION OVERHEADS

There has been no change in the methodology employed or the procedures followed in capitalizing the allowance for funds used during construction and other construction overheads as was reported in the Company's last FERC Form 1.

MONTANA-DAKOTA UTILITIES CO.
SIGNIFICANT CHANGES IN
INTANGIBLE PLANT

There have been no significant changes in Intangible Plant balances since the end of the year reported in the Company's last FERC Form 1.

MONTANA-DAKOTA UTILITIES CO.
WORKING PAPERS ON PLANT
NOT USED & USEFUL

Montana-Dakota has no such plant.

MONTANA-DAKOTA UTILITIES CO.
DESCRIPTION OF PROPERTY RECORDS

The Company's Continuing Property Records are maintained in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission (FERC). The Plant Accounting System, which is computerized, records additions to utility plant at original cost (including overhead costs and an allowance for funds used during construction) through charges to work orders maintained in the Plant Accounting Construction Work in Progress (CWIP) System.

As construction projects are completed and the plant is placed in service, the costs accumulated in related work orders are unitized and transferred to FERC Account 101, Plant in Service. Such costs are recovered from utility customers through depreciation charges to cost of service. Upon retirement or other disposition of the plant property units, in the ordinary course of business, the original cost is transferred from Account 101 and charged to Account 108, Accumulated Provision for Depreciation of Utility Plant, plus or minus any net salvage.

MONTANA-DAKOTA UTILITIES CO.
GAS PLANT ACQUISITIONS WITHOUT REGULATORY APPROVAL
TWELVE MONTHS ENDING DECEMBER 31, 2003

None.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT B

Function	Balance @ 12/31/02	Balance @ 12/31/03	Average Balance @ 12/31/03	Provision for Depreciation	Pro Forma Balance @ 12/31/04	Average Balance	Pro Forma Adjustment
Distribution	$20,849,100	$22,154,928	$21,502,014	$1,306,376	$23,461,304	$22,808,116	$1,306,102
General	2,532,093	1,451,593	1,991,843	744,820	2,196,413	1,824,003	(167,840)
General Intangible	131,474	136,094	133,784	749	136,843	136,468	2,684
Common	515,942	424,484	470,213	118,633	543,117	483,801	13,588
Common Intangible	482,674	673,004	577,839	127,592	800,596	736,800	158,961
Gas Plant Leased to others	(91)	(91)	(91)	0	(91)	(91)	0
CWIP in Service				1/	1/	1/	1/
Total	$24,511,192	$24,840,012	$24,675,602	$2,298,170	$27,138,182	$25,989,097	$1,313,495

1/ Included in the above functions.

DOCKET NO. _____
RULE 20:10:13:64
STATEMENT E
PAGE 1 OF 2

MONTANA-DAKOTA UTILITIES CO.
MONTHLY ACCUMULATED PROVISIONS FOR DEPRECIATION BY FUNCTION
GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Function	December 2002	January 2003	February	March	April	May	June	July	August	September	October	November	December
Distribution	$105,038,561	$105,576,337	$106,048,471	$106,587,069	$107,114,568	$107,635,534	$108,172,404	$108,663,398	$109,193,209	$109,584,359	$109,983,768	$110,463,956	$110,971,485
General	9,493,634	9,581,189	9,605,123	9,277,619	8,904,334	8,959,814	8,856,950	8,887,438	8,942,632	6,606,681	6,613,289	6,624,416	6,739,680
Total	$114,532,195	$115,157,526	$115,653,594	$115,864,688	$116,018,902	$116,595,348	$117,029,354	$117,550,836	$118,135,841	$116,191,040	$116,597,057	$117,088,372	$117,711,165

DOCKET NO. RULE 20:10:13:64
STATEMENT E
PAGE 2 OF 2

MONTANA-DA. ?A UTILITIES CO.
BOOK CHANGES IN ACCUMULATED PROVISION FOR
DEPRECIATION AND AMORTIZATION - GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Gas Utility	Beginning Balance 12/31/02	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 12/31/03
Account 111.2 - Intangible	$447,917	$10,455					$458,372
Account 108							
Distribution	105,038,561	6,785,125	$799,928	$129,163	$437,618	$256,182	110,971,485
General	9,493,634	1,193,769	4,050,001	1,053,238	1,008	(949,952)	6,739,680
Total Account 108	114,532,195	7,978,894	4,849,929	1,182,401	438,626	(693,770)	117,711,165
Account 115 - Acquisition Adjustment	0	29,837					29,837
Total	$114,980,112	$8,019,186	$4,849,929	$1,182,401	$438,626	($693,770)	$118,199,374
Common 1/	$6,858,790						$7,704,993

1/ Common Plant is assigned by state on an actual site and use basis when applicable, and the remainder is allocated by state to gas and electric on a plant in service basis. Total common changes for the twelve months ended December 31, 2003 are:

Common Utility	Beginning Balance 12/31/02	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 12/31/03
Account 111.4	$6,426,442	$1,358,967	$0	$0	$0	$0	$7,785,409
Account 108	19,876,689	2,215,960	4,772,909	831,296	11,992	(1,142,452)	16,996,592
Total Accounts 111.4 and 108	$26,303,131	$3,574,927	$4,772,909	$831,296	$11,992	($1,142,452)	$24,782,001

DOCKET NO. _____
RULE 20:10:13:65
STATEMENT E
SCHEDULE E-1
PAGE 1 OF 1

MONTANA-DAKOTA UTILITIES CO.
PROCEDURES FOLLOWED IN DEPRECIATING OR AMORTIZING PLANT AND RECORDING ABANDONMENT

Effective January 1, 2004, the methodology for certain general plant accounts changed from depreciation to amortization. Under 'General Plant Amortization' methodology, the individual assets within a FERC plant account are amortized over the average service life derived for that account and retired at the time the asset is fully amortized, regardless of the actual physical disposal rate.

MONTANA-DAKOTA UTILITIES CO.
ALLOCATION OF OVERALL ACCUMULATED RESERVE ACCOUNTS TO FUNCTIONAL GROUPS OF PLANTS

This schedule is not applicable because the Company provides and records its accumulated reserves for depreciation by functional groups of plant accounts.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF WORKING CAPITAL AND
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Working Capital	Balance @ 12/31/02	Balance @ 12/31/03	Average	Pro Forma Adjustments	Pro Forma Balances
Materials and Supplies	$287,723	$253,659	$270,691	($5,151)	$265,54(
Prepaid Insurance	17,823	39,592	28,708	63,192	91,90(
Unamortized FAS 106	158,631	142,768	150,700	(15,864)	134,83(
Total Working Capital	$464,177	$436,019	$450,099	$42,177	$492,27(
Customer Advances for Construction	$81,813	$63,222	$72,518	($17,666)	$54,85(

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
BY PRINCIPAL ITEM OF MAIN ACCOUNT
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Description	12/31/02	12/31/03	Average
Natural Gas Material	$286,572	$255,735	$271,153
Transportation Material	2,606	2,397	2,502
All Other Gas Material	0	0	0
Reserve for Inventory Shrinkage	(1,455)	(4,473)	(2,964)
Total	$287,723	$253,659	$270,691

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT C

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2002	$287,723	$253,659	
January 2003	247,598	225,504	
February	235,168	215,238	
March	231,149	228,931	
April	242,360	242,360	
May	272,287	272,287	
June	292,817	292,817	
July	289,396	289,396	
August	301,084	301,084	
September	290,730	290,730	
October	309,044	309,044	
November	277,306	277,306	
December	253,659	253,659	
Beginning and ending average	$270,691		
Thirteen month average		$265,540	($5,151)

1/ Reflects actual data through March 2004 and remainder of months to remain at the 2003 level.

MONTANA-DAKOTA UTILITIES CO.
PREPAID INSURANCE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT D

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2002	$17,823	$39,592	
January 2003	5,980	183,483	
February	98,307	165,840	
March	86,370	148,197	
April	138,748	132,597	
May	121,737	114,979	
June	113,774	97,361	
July	99,687	79,743	
August	80,000	62,125	
September	65,923	44,504	
October	59,519	26,886	
November	66,031	58,404	
December	39,592	40,995	
Beginning and ending average	$28,708		
Thirteen month average		$91,900	$63,192

1/ Reflects actual data through March 2004. April - December based on insurance expense.

MONTANA-DAKOTA UTILITIES CO.
UNAMORTIZED FAS 106
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT E

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2002	$158,631	$142,768	
January 2003	157,309	141,446	
February	155,987	140,124	
March	154,666	138,802	
April	153,344	137,480	
May	152,022	136,158	
June	150,700	134,836	
July	149,378	133,514	
August	148,056	132,192	
September	146,734	130,870	
October	145,412	129,548	
November	144,090	128,226	
December	142,768	126,904	
Beginning and Ending Average	$150,700		
Thirteen Month Average		$134,836	($15,864)

1/ Reflects actual data through March 2004. April - December reflects current amortization.

MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT I

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2002	$81,813	$63,222	
January 2003	57,488	63,778	
February	57,373	48,266	
March	57,531	48,822	
April	57,738	57,738	
May	57,896	57,896	
June	44,711	44,711	
July	45,426	45,426	
August	50,590	50,590	
September	51,305	51,305	
October	52,019	52,019	
November	66,077	66,077	
December	63,222	63,222	
Beginning and ending average	$72,518		
13 month average		$54,852	($17,666)

1/ Reflects actual data through March 2004. Remainder of months to remain at 2003 levels.

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
GAS UTILITY - SOUTH DAKOTA
MONTHLY BALANCES FOR YEARS ENDED
DECEMBER 31, 2001 AND DECEMBER 31, 2002

	12/31/01	12/31/02
January	$191,723	$203,557
February	182,221	202,311
March	202,716	249,521
April	261,667	243,926
May	250,993	243,876
June	281,081	299,635
July	266,912	308,209
August	291,248	319,475
September	265,291	292,780
October	274,796	292,203
November	227,342	327,558
December	215,239	287,723

MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY
TWELVE MONTHS ENDING DECEMBER 31, 2003

Refer to Rule 20:10:13:69, Schedule F-1, page 5.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY CAPITAL STRUCTURE
2003

	Balance	Capital Ratio	Cost	Required Return
Long Term Debt	$147,600,000	45.783%	8.878%	4.065%
Preferred Stock	16,250,000	5.040%	4.622%	0.233%
Common Equity	158,539,438	49.177%	11.000%	5.409%
Total	$322,389,438	100.000%		9.707%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY CAPITAL STRUCTURE
PROJECTED 2004

	Balance	Capital Ratio	Cost	Required Return
Long Term Debt	$154,100,000	45.589%	8.624%	3.932%
Preferred Stock	16,150,000	4.778%	4.618%	0.221%
Common Equity	167,772,745	49.633%	11.000%	5.460%
Total	$338,022,745	100.000%		9.613%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
2003

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
First Mortgage Bonds			
Balance at 12/31/02	$130,850,000	$11,743,442	8.975%
Amortization of Gain/Loss		361,666	
	130,850,000	12,105,108	
Balance at 12/31/03	160,850,000	13,604,942	8.458%
Amortization of Gain/Loss		268,627	
	160,850,000	13,873,569	
Average Balance	$145,850,000	$12,674,192	8.690%
Average Amort. of Gain/Loss		315,147	
	$145,850,000	$12,989,339	8.906%
Pollution Control Bonds			
Balance at 12/31/02	$2,000,000	$131,120	6.556%
Balance at 12/31/03	1,500,000	98,340	6.556%
Average Balance	$1,750,000	$114,730	6.556%
Total Average Long Term Debt	$147,600,000	$13,104,069	8.878%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
PROJECTED 2004

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
First Mortgage Bonds			
Balance at 12/31/03	$160,850,000	$13,604,942	8.458%
Amortization of Gain/Loss		268,627	
	160,850,000	13,873,569	
Balance at 12/31/04	145,850,000	12,433,292	8.525%
Amortization of Gain/Loss		174,668	
	145,850,000	12,607,960	
Average Balance	$153,350,000	$13,019,117	8.490%
Average Amort. of Gain/Loss		221,648	
	$153,350,000	$13,240,765	8.634%
Pollution Control Bonds			
Balance at 12/31/03	$1,500,000	$98,340	6.556%
Balance at 12/31/04	0	0	
Average Balance	$750,000	$49,170	6.556%
Total Average Long Term Debt	$154,100,000	$13,289,935	8.624%

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2003

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
First Mortgage Bonds:									
Secured Medium-term Notes, Series A:									
8.25%	04/01/92	04/01/07	8.250%	$30,000,000	$30,000,000	$225,000	0.750%	$3,663,204	12.211%
8.6%	04/01/92	04/01/12	8.600%	35,000,000	34,911,100	306,250	0.877%	5,698,318	16.322%
6.52%	09/30/97	10/01/04	6.520%	15,000,000	15,000,000	90,000	0.600%	827,077	5.514%
6.71%	09/30/97	10/01/09	6.710%	15,000,000	15,000,000	93,750	0.625%	1,417,846	9.452%
5.83%	09/18/98	10/01/08	5.830%	15,000,000	15,000,000	93,750	0.625%	92,336	0.616%
5.98% - Senior Note	12/15/03	12/15/33	5.980%	30,000,000	30,000,000	262,500	0.875%	280,668	0.936%
Pollution Control Refunding Revenue Bonds:									
Mercer County 6.65%	06/01/92	06/01/22	6.650%	15,000,000	15,000,000	0	0.000%	938,724	6.258%
Richland County 6.65%	06/01/92	06/01/22	6.650%	3,250,000	3,250,000	0	0.000%	186,323	5.733%
Morton County 6.65%	06/01/92	06/01/22	6.650%	2,600,000	2,600,000	0	0.000%	179,014	6.885%
Pollution Control Notes:									
Grant County 6.2%	03/01/74	03/01/04	6.200%	5,600,000	5,600,000	84,000	1.500%	88,958	1.589%
				$166,450,000	$166,361,100	$1,155,250		$13,372,468	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
First Mortgage Bonds:						
Secured Medium-term Notes, Series A:						
8.25%	$26,111,796	87.039%	10.177%	$30,000,000	$3,053,100	
8.6%	28,906,532	82.590%	11.020%	35,000,000	3,857,000	
6.52%	14,082,923	93.886%	7.811%	15,000,000	1,171,650	
6.71%	13,488,404	89.923%	8.195%	15,000,000	1,229,250	
5.83%	14,813,914	98.759%	6.086%	15,000,000	912,900	
5.98% - Senior Note	29,456,832	98.189%	6.205%	30,000,000	1,861,500	
Pollution Control Refunding Revenue Bonds:						
Mercer County 6.65%	14,061,276	93.742%	7.288%	15,000,000	1,093,200	
Richland County 6.65%	3,063,677	94.267%	7.243%	3,250,000	235,398	
Morton County 6.65%	2,420,986	93.115%	7.344%	2,600,000	190,944	
Total First Mortgage Bonds	146,406,340			160,850,000	13,604,942	8.458%
Pollution Control Notes:						
Grant County 6.2%	5,427,042	96.911%	6.556%	1,500,000	98,340	6.556%
Total Long-Term Debt Capital	$151,833,382			$162,350,000	$13,703,282	8.441%

Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

DOCKET NO. RULE 20:10:13:73
STATEMENT G
PAGE 3 OF 6

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2004

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
First Mortgage Bonds:									
Secured Medium-term Notes, Series A:									
8.25%	04/01/92	04/01/07	8.250%	$30,000,000	$30,000,000	$225,000	0.750%	$3,663,204	12.211%
8.6%	04/01/92	04/01/12	8.600%	35,000,000	34,911,100	306,250	0.877%	5,698,318	16.322%
6.71%	09/30/97	10/01/09	6.710%	15,000,000	15,000,000	93,750	0.625%	1,417,846	9.452%
5.83%	09/18/98	10/01/08	5.830%	15,000,000	15,000,000	93,750	0.625%	92,336	0.616%
5.98% - Senior Note	12/15/03	12/15/33	5.980%	30,000,000	30,000,000	262,500	0.875%	280,668	0.936%
Pollution Control Refunding Revenue Bonds:									
Mercer County 6.65%	06/01/92	06/01/22	6.650%	15,000,000	15,000,000	0	0.000%	938,724	6.258%
Richland County 6.65%	06/01/92	06/01/22	6.650%	3,250,000	3,250,000	0	0.000%	186,323	5.733%
Morton County 6.65%	06/01/92	06/01/22	6.650%	2,600,000	2,600,000	0	0.000%	179,014	6.885%
				$145,850,000	$145,761,100	$981,250		$12,456,433	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
First Mortgage Bonds:						
Secured Medium-term Notes, Series A:						
8.25%	$26,111,796	87.039%	10.177%	$30,000,000	$3,053,100	
8.6%	28,906,532	82.590%	11.020%	35,000,000	3,857,000	
6.71%	13,488,404	89.923%	8.195%	15,000,000	1,229,250	
5.83%	14,813,914	98.759%	6.086%	15,000,000	912,900	
5.98% - Senior Note	29,456,832	98.189%	6.205%	30,000,000	1,861,500	
Pollution Control Refunding Revenue Bonds:						
Mercer County 6.65%	14,061,276	93.742%	7.288%	15,000,000	1,093,200	
Richland County 6.65%	3,063,677	94.267%	7.243%	3,250,000	235,398	
Morton County 6.65%	2,420,986	93.115%	7.344%	2,600,000	190,944	
Total First Mortgage Bonds	132,323,417			145,850,000	12,433,292	8.525%
Total Long-Term Debt Capital	$132,323,417			$145,850,000	$12,433,292	8.525%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

DOCKET NO. _____
RULE 20:10:13:73
STATEMENT G
PAGE 4 OF 6

MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
2003

		Projected Average Amortization
Acct. 1890 - Unamortized Loss		
9 1/8% due 05-15-06	1/03 - 12/03	$361,666
9 1/8% due 05-15-06	1/04 - 12/04	268,627
Average at 12/31/03		$315,147

MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
PROJECTED 2004

		Projected Average Amortization
Acct. 1890 - Unamortized Loss		
9 1/8% due 05-15-06	1/04 - 12/04	$268,627
9 1/8% due 05-15-06	1/05 - 12/05	174,668
Average at 12/31/04		$221,648

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
2003

Description	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
Balance at 12/31/02	$16,300,000	$753,705	4.624%
Redemptions:			
5.1% Series	(100,000)	(5,285)	
Balance at 12/31/03	$16,200,000	$748,420	4.620%
Average Preferred Stock	$16,250,000	$751,063	4.622%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
PROJECTED 2004

Description	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
Balance at 12/31/03	$16,200,000	$748,420	4.620%
Redemptions:			
5.1% Series	(100,000)	(5,285)	
Balance at 12/31/04	$16,100,000	$743,135	4.616%
Average Preferred Stock	$16,150,000	$745,778	4.618%

MONTANA-DAKOTA UTILITIES CO.
PREFERRED STOCK CAPITAL
DECEMBER 31, 2003

Description	Date of Issuance	Call (Redemption) Price	Dividend Rate	Par Value of Issue	Gross Proceeds (000's)	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Issuance Expense Amount	Issuance Expense % Gross Proceeds
4.5% Series	01/01/51	$105	4.5%	$100	$10,000				
4.7% Series	12/07/55	102	4.7%	100	5,000				
5.1% Series	05/23/61	100/102	5.1%	100	5,000	$25,000	0.50%	$27,452	0.549%

Description	Net Proceeds Amount (000's)	Net Proceeds Per Unit	Cost of Money 1/ 2/	December 31, 2003 Principal Outstanding	December 31, 2003 Annual Cost	December 31, 2003 Embedded Cost	Method of Offering
4.5% Series	$10,000	100.000%	4.500%	$10,000,000	$450,000		Public
4.7% Series	5,000	100.000%	4.700%	5,000,000	235,000		Public
5.1% Series	4,948	98.951%	5.285%	1,200,000	63,420		Private
Total				$16,200,000	$748,420	4.620%	

1/ Yield to maturity based upon the life, net proceeds, and quarterly compounding of the stated dividend rate of each issue.
2/ 4.5% Series and 4.7% Series issue expense fully recovered.

DOCKET NO. _____
RULE 20:10:13:74
STATEMENT G
PAGE 3 OF 3

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
2003

Description	Amount
Common Equity - 12/31/02	$1,287,371,219
Unappropriated Retained Earnings of Subsidiaries	430,566,718
Additional Equity of Subsidiaries (Centennial)	700,137,104
Utility Common Equity - 12/31/02	$156,667,397
Common Equity - 12/31/03	$1,439,261,641
Unappropriated Retained Earnings of Subsidiaries	528,082,638
Additional Equity of Subsidiaries	750,767,525
Utility Common Equity - 12/31/03	$160,411,478
Average Common Utility Equity - 12/31/03	$158,539,438

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
PROJECTED 2004

Description	Amount
Common Equity - 12/31/03	$1,439,261,641
Unappropriated Retained Earnings of Subsidiaries	528,082,638
Additional Equity of Subsidiaries	750,767,525
Utility Common Equity - 12/31/03	$160,411,478
Common Equity Infusion	18,000,000
Projected Equity Earnings	14,662,000
Less: Utility Dividends	(17,939,466)
Utility Common Equity - 12/31/04	$175,134,012
Average Common Utility Equity - 12/31/04	$167,772,745

MDU Resources Group Inc.
Equity Issuance - 1999- 2003

	DRIP			401-K			Acquisition			Equity Draw Down			Employee Stock Exercise			
Period	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares Outstanding
Beginning Balance																79,909,426
Jan-99	84,171	1,497,514	5,611	71,640	1,274,595	4,776										80,065,237
Feb-99	13,758	214,150	917													80,078,995
Mar-99	14,292	219,744	953													80,093,287
Apr-99																80,093,287
May-99																80,093,287
Jun-99							1,347,155	17,869,396	5,000							81,440,442
Jul-99																81,440,442
Aug-99							774,991	10,279,912	5,000							82,215,433
Sep-99							3,141,773	41,674,193	5,000							85,357,206
Oct-99																85,357,206
Nov-99							559,666	7,423,723	5,000							85,916,872
Dec-99																85,916,872
Jan-00							27,378	363,157	5,000							85,944,250
Feb-00																85,944,250
Mar-00																85,944,250
Apr-00							1,899,056	25,190,114	5,000							87,843,306
May-00							4,239,130	56,230,152	5,000							92,082,436
Jun-00							197,186	2,615,577	5,000							92,279,622
Jul-00							1,805,784	23,952,909	5,000	332,667	4,753,939	118,848				94,418,073
Aug-00							845,728	11,218,207	5,000	364,233	5,445,825	136,146				95,628,034
Sep-00										1,071,567	17,078,277	426,957				96,699,601
Oct-00							15,640	207,464	5,000	296,429	5,454,667	136,367				97,011,670
Nov-00										369,798	6,899,491	172,487				97,381,468
Dec-00							124,752	1,654,779	5,000	395,130	7,616,272	190,407				97,901,350
Jan-01							252,603	3,350,665	5,000							98,153,953
Feb-01										793,181	14,999,974	374,999				98,947,134
Mar-01							144,489	1,916,581	5,000	537,643	10,000,000	250,000	32,721	693,249		99,661,987
Apr-01							2,477,229	32,859,324	5,000				93,378	2,356,861		102,232,594
May-01													31,650	804,332		102,264,244
Jun-01							140,625	1,865,327	5,000				4,950	112,827		102,409,819
Jul-01													4,500	91,350		102,414,319
Aug-01													5,325	106,145		102,419,644
Sep-01										1,658,030	25,000,000	625,000	1,800	30,648		104,079,474
Oct-01													1,026	17,018		104,080,500
Nov-01													1,350	22,347		104,081,850
Dec-01							88,224	1,170,252	5,000	853,597	15,000,000	375,000	1,605	22,275		105,025,276
Jan-02													1,470	20,301		105,026,746
Feb-02							141,378	2,365,217	5,000				2,925	40,394		105,171,049
Mar-02							752,367	13,192,858	5,000				1,841	25,424		105,925,257
Apr-02							700,001	12,759,864	5,000				4,826	66,647		106,630,084
May-02							133,742	2,364,071	5,000				1,575	21,751		106,765,401
Jun-02							731,050	11,121,768	5,000				675	9,322		107,497,126
Jul-02													600	8,286		107,497,726

DOCKET NO. RULE 20:10:13:75
STATEMENT G
PAGE 3 OF 4

MDU Resources Group Inc.
Equity Issuance - 1999- 2003

	DRIP			401-K			Acquisition			Equity Draw Down			Employee Stock Exercise			
Period	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares Outstanding
Aug-02							23,243	550,776	5,000				465	6,422		107,521,434
Sep-02													660	9,115		107,522,094
Oct-02							345,307	4,807,716	5,000				450	6,215		107,867,851
Nov-02										3,150,000	48,888,000	1,222,200	450	6,215		111,018,301
Dec-02							(469)			405,000	6,285,600	157,140	225	3,107		111,423,057
Jan-03													25	345		111,423,082
Feb-03													677	9,349		111,423,759
Mar-03							80,836	1,125,487	5,000				1,037	14,321		111,505,632
Apr-03							200,994	3,348,547	5,000				1,575	21,751		111,708,201
May-03													3,525	48,680		111,711,726
Jun-03													7,150	98,742		111,718,876
Jul-03							1,851,536	35,218,293	5,000				3,825	52,823		113,574,237
Aug-03													1,350	18,644		113,575,587
Sep-03													7,725	106,682		113,583,312
Oct-03													11,057	152,697		113,594,369
Nov-03													1,068	14,749		113,595,437
Dec-03							118,570	2,265,101	5,000				2,625	36,251		113,716,632
Totals	112,221	1,931,408	7,481 (1)	71,640	1,274,595	4,776 (1)	23,159,964	328,961,430	140,000 (2)	10,227,275	167,422,045	4,185,551 (4)	236,106	5,055,283	-	

Footnotes:
(1) Assumed to be $.10 per share.
(2) Estimated Legal & Administrative costs of $5,000 per transaction.
(3) $2,058,000 underwriters discount plus $350,000 other expenses (legal, administrative, etc.).
(4) Underwriters discount estimated at 2.5 percent of market based on negotiated average price at draw-down.

DOCKET NO. _____
RULE 20:10:13:75
STATEMENT G
PAGE 4 OF 4

MDU RESOURCES GROUP, INC.
STOCK DIVIDENDS, STOCK SPLITS OR CHANGES IN PAR OR STATED VALUE
FOR THE FIVE-YEAR PERIOD ENDING DECEMBER 31, 2003

On April 30, 1999, the MDU Resources Group, Inc. Certificate of Incorporation was amended pursuant to stockholder approval. The amendment to the Certificate of Incorporation increased the number of shares of common stock which the company is authorized to issue from 75,000,000 shares of common stock with a par value of $3.33 to 150,000,000 shares with a par value of $1.00.

On October 29, 2003, MDU Resources Group, Inc. issued 37,862,129 additional shares of Common Stock, Par value $1.00, in connection with a three-for-two Common Stock split to be effected in the form of a fifty percent stock dividend.

MDU RESOURCES GROUP, INC.
COMMON STOCK DATA
FOR THE FIVE YEARS ENDED DECEMBER 31, 2003

	Avg. Number of Shares Outstanding (000's) 2/	Annual Diluted Earnings (per share) 2/	Annual Dividends (per share) 2/	Dividend/ Earnings Ratio	Average Market Price 1/	Price/ Earnings Ratio	Dividend/ Price Ratio
Year Ended December 31:							
1999	82,306	1.01	0.5467	54%	15.27	15.1	3.6%
2000	92,085	1.20	0.5733	48%	16.02	13.4	3.6%
2001	101,803	1.52	0.6000	39%	20.17	13.3	3.0%
2002	106,863	1.38	0.6266	45%	17.59	12.7	3.6%
2003	112,460	1.55	0.6600	43%	20.91	13.5	3.2%
Twelve Months:							
January 2003	107,427	1.28	0.6266	49%	17.54	13.7	3.6%
February	107,845	1.25 3/	0.6333	51%	17.46	14.0	3.6%
March	108,362	1.33	0.6333	48%	18.09	13.6	3.5%
April	108,831	1.36	0.6333	47%	19.09	14.0	3.3%
May	109,232	1.40	0.6400	46%	20.30	14.5	3.2%
June	109,610	1.48	0.6400	43%	22.18	15.0	2.9%
July	110,083	1.53	0.6400	42%	21.84	14.3	2.9%
August	110,601	1.56	0.6500	42%	21.67	13.9	3.0%
September	111,117	1.57	0.6500	41%	22.68	14.4	2.9%
October	111,648	1.58	0.6500	41%	23.22	14.7	2.8%
November	112,155	1.55	0.6600	43%	22.97	14.8	2.9%
December	112,460	1.55	0.6600	43%	23.84	15.4	2.8%

1/ The average market price is based on monthly high and low for the year.
2/ Common stock amounts reflect the Company's three-for-two common stock split effective October 29, 2003.
3/ Includes the cumulative effect of the change in accounting for asset retirement obligations as required by the adoption of Statement of Financial Accounts Standards No. 143 (February - December 2003).

DOCKET NO. _____
RULE 20:10:13:77
STATEMENT G
SCHEDULE G-2
PAGE 1 OF 1

MONTANA-DAKOTA UTILITIES CO.
REACQUISITION OF BONDS OR PREFERRED STOCK
FOR THE FIVE-YEAR PERIOD ENDING DECEMBER 31, 2003

First Mortgage Bonds

There was no reacquisition of bonds during the five years ending December 31, 2003.

Preferred Stock

Title	Principal Amount	Reacquisition Cost	Gain or (Loss)
Preferred Stock:			
5.1% Preferred Stock	$500,000	$500,000	$0

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	South Dakota	Pro Forma Adjustments	Pro Forma
Cost of Gas	$34,335,947	$11,747,188	$46,083,135
Other Gas Supply	66,813	4,036	70,849
Distribution	2,719,198	419,189	3,138,387
Customer Accounts	1,446,693	148,009	1,594,702
Customer Service & Infor.	49,845	4,714	54,559
Sales	273,956	(4,489)	269,467
Administrative and General	2,708,304	680,920	3,389,224
Total Operation and Maintenance Expenses	$41,600,756	$12,999,567	$54,600,323

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Account No.		Per Books	Pro Forma Adjustments	Pro Forma
	Other Gas Supply Expenses			
804	Natural Gas City Gate Purchases	$39,437,109		
805.1	Purchased Gas Cost Adjustments	(2,914,578)		
808.1	Gas Withdrawn from Storage	7,138,560		
808.2	Gas Delivered to Storage	(9,325,144)		
812	Gas Used for Other Utility Operations - Cr.			
813	Other Gas Supply Expenses	66,813		
	Total Other Gas Supply Expenses	$34,402,760	$11,751,224	$46,153,984
	Distribution Expenses			
	Operation			
870	Supervision and Engineering	$419,454		
871	Distribution Load Dispatching	29,661		
874	Mains and Services	658,165		
875	Measuring & Reg. Station Exp. - General	6,403		
876	Measuring & Reg. Station Exp. - Industrial	7,023		
877	Measuring & Reg. Station Exp. - City Gate			
878	Meters and House Regulators	310,576		
879	Customer Installations	408,227		
880	Other Expenses	607,494		
881	Rents	17,705		
	Total Operation Expenses	$2,464,708		
	Maintenance			
885	Supervision & Engineering	$66,907		
886	Structures & Improvements	1,394		
887	Mains	33,233		
889	Measuring & Reg. Station Exp. - General	10,887		
890	Measuring & Reg. Station Exp. - Industrial	6,089		
891	Measuring & Reg. Station Exp. - City Gate			
892	Services	8,505		
893	Meters and House Regulators	49,002		
894	Other Equipment	78,473		
	Total Maintenance Expenses	$254,490		
	Total Distribution Expenses	$2,719,198	$419,189	$3,138,387
	Customer Accounts Expenses			
	Operation			
901	Supervision	$103,836		
902	Meter Reading Expenses	316,275		
903	Customer Records and Collection Exp.	807,722		
904	Uncollectible Accounts	139,486		
905	Misc. Customer Accounts Expenses	79,374		
	Total Customer Accounts Expenses	$1,446,693	$148,009	$1,594,702

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Account No.		Per Books	Pro Forma Adjustments	Pro Forma
	Customer Service & Information Expenses			
	Operation			
907	Supervision	$2,179		
908	Customer Assistance Expenses	35,585		
909	Informational and Instructional Expenses	12,081		
910	Misc. Customer Service & Info. Exp.			
	Total Customer Service & Info. Exp.	$49,845	$4,714	$54,559
	Sales Expenses			
	Operation			
911	Supervision	$46,345		
912	Demonstrating and Selling Expenses	187,077		
913	Advertising Expenses	26,496		
916	Misc. Sales Expenses	14,038		
	Total Sales Expenses	$273,956	($4,489)	$269,467
	Administrative & General Expenses			
	Operation			
920	Administrative and General Salaries	$812,643		
921	Office Supplies and Expenses	458,751		
923	Outside Services Employed	114,876		
924	Property Insurance	85,898		
925	Injuries and Damages	257,608		
926	Employee Pensions and Benefits	778,018		
927	Franchise Requirements			
928	Regulatory Commission Expenses	1,869		
930.1	General Advertising Expenses	5,647		
930.2	Miscellaneous General Expenses	74,522		
931	Rents	32,830		
	Total Operation Expenses	$2,622,662		
	Maintenance			
935	Maintenance of General Plant	$85,642		
	Total Administrative & General Expenses	$2,708,304	$680,920	$3,389,224
	Total Operation & Maintenance Expenses	$41,600,756	$12,999,567	$54,600,323

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PRO FORMA

Function	Total	Cost of Gas	Labor	Benefits	Insurance	Contract Labor	Vehicles & Work Equip.	Postage	Telephone
Cost of Gas	$46,083,135	$46,083,135							
Other Gas Supply	70,849		$63,087			$518	$155		
Distribution	3,138,387		2,120,035			438,447	459,956	$5,291	$35,215
Customer Accounting	1,594,702		940,013			119,356	61,111	117,549	8,198
Customer Service & Information	54,559		34,275			4	4,811	0	0
Sales	269,467		227,929			431	14,313	646	4,754
Administrative and General	3,389,224		923,330	$1,237,612	$211,058	157,015	11,828	31,948	55,280
Total Other O&M	8,517,188	0	4,308,669	1,237,612	211,058	715,771	552,174	155,434	103,447
Total O&M	$54,600,323	$46,083,135	$4,308,669	$1,237,612	$211,058	$715,771	$552,174	$155,434	$103,447

DOCKET NO.
RULE 20:10:13:81
STATEMENT H
SCHEDULE H-1
PAGE 1 OF 21

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2003
PRO FORMA

Function	Office Supplies	Company Consumption	Uncollectible Accounts	Computer Rental	Industry Dues	Advertising	Regulatory Commission Expense	Depreciation Study Expense	All Other O&M
Cost of Gas									$0
Other Gas Supply	$67								7,022
Distribution	7,006	$18,436							54,001
Customer Accounting	16,746	7,780	$209,033	$30,433					84,483
Customer Service & Information	82					$12,081			3,306
Sales	1,663	1,092				0			18,639
Administrative and General	62,721	17,099		19,503	$24,589	5,499	$156,306	$3,050	472,386
Total Other O&M	88,285	44,407	209,033	49,936	24,589	17,580	156,306	3,050	639,837
Total O&M	$88,285	$44,407	$209,033	$49,936	$24,589	$17,580	$156,306	$3,050	$639,837

DOCKET NO. _____
RULE 20:10:13:81
STATEMENT H
SCHEDULE H-1
PAGE 2 OF 21

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA COST OF GAS
GAS UTILITY - SOUTH DAKOTA
ADJUSTMENT NO. 6

	Pro Forma Dk Sales	Dk Adjusted for Distribution Losses 1/	Commodity Charge 2/	Pro Forma Cost of Gas
Residential	3,280,458	3,317,615	$6.898	$22,884,908
Firm General Service	2,239,643	2,265,011	6.898	15,624,046
Air Force 3/	573,102	573,102	5.646	3,235,734
Small Interruptible	25,747	26,039	6.898	179,617
Large Interruptible 4/	728,477	736,728	5.645	4,158,830
Total	6,847,427	6,918,495		$46,083,135
Per Books Cost of Gas				$34,335,947
Pro Forma Adjustment				$11,747,188

1/ Distribution loss factor of 1.12%.
2/ June 1, 2004 Purchased Gas Adjustment reflecting weighted seasonal demand and annual gas commodity
3/ The Air Force owns its distribution system so there are no distribution losses.
4/ Includes firm contract volumes.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
LABOR EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 7

	Per Books		Pro Forma	Pro Forma
	Gas Utility	South Dakota	South Dakota 1/	Adjustment
Gas Supply	$311,974	$59,059	$63,087	$4,028
Distribution	10,422,764	1,984,680	2,120,035	135,355
Customer Accounting	4,706,799	879,997	940,013	60,016
Customer Service	210,030	32,087	34,275	2,188
Sales	929,061	213,377	227,929	14,552
A&G	4,180,307	864,379	923,330	58,951
Total	$20,760,935	$4,033,579	$4,308,669	$275,090

1/ Reflects average 6.82% increase reflecting average 2002-2004 bonus.

MONTANA-DAKOTA UTILITIES CO.
BENEFITS EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 8

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma	Adjustment
Medical/Dental	$1,775,991	$348,281	$429,291	$81,010
Pension expense	(488,642)	(95,458)	139,999	235,457
Post-retirement	1,455,894	288,819	308,834	20,015
401-K	520,003	103,310	111,523	8,213
Workers compensation	203,593	45,817	49,119	3,302
SISP			198,846	198,846
Total	$3,466,839	$690,769	$1,237,612	$546,843

MONTANA-DAKOTA UTILITIES CO.
INSURANCE EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 9

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma	Adjustment
A&G	$1,216,349	$255,242	$211,058	($44,184)

MONTANA-DAKOTA UTILITIES CO.
CONTRACT LABOR AND CONSULTING SERVICES EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 10

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
Other Gas Supply 1/	$3,073	$582	$518	($64)
Distribution 2/	1,107,647	379,312	438,447	59,135
Customer Accounting 1/	263,247	134,183	119,356	(14,827)
Customer Service 1/	25	5	4	(1)
Sales 1/	1,792	484	431	(53)
A&G 1/	867,613	176,520	157,015	(19,505)
Total Contract Labor	$2,243,397	$691,086	$715,771	$24,685

1/ Reflects a decrease of 11.05%.
2/ Reflects an increase of 15.59%.

MONTANA-DAKOTA UTILITIES CO.
VEHICLES AND WORK EQUIPMENT
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 11

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
Other Gas Supply	$377	$71	$155	$84
Distribution	1,012,689	237,562	459,956	222,394
Customer Accounting	172,142	28,806	61,111	32,305
Customer Service	9,390	2,270	4,811	2,541
Sales	32,544	6,746	14,313	7,567
A&G	27,365	5,576	11,828	6,252
Total Company Vehicles	$1,254,507	$281,031	$552,174	$271,143

1/ Based on pro forma plant and proposed depreciation rates.

MONTANA-DAKOTA UTILITIES CO.
POSTAGE EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 12

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
Distribution	$29,119	$5,451	$5,291	($160)
Customer Accounting	643,024	121,097	117,549	(3,548)
Customer Service	8	0	0	0
Sales	7,087	666	646	(20)
A&G	156,768	32,912	31,948	(964)
Total Postage	$836,006	$160,126	$155,434	($4,692)

1/ Reflects a decrease of 2.93%.

MONTANA-DAKOTA UTILITIES CO.
TELEPHONE EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 13

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
Distribution	$220,852	$35,092	$35,215	$123
Customer Accounting	64,313	8,169	8,198	29
Customer Service	1,415	0	0	0
Sales	21,336	4,737	4,754	17
A&G	262,514	55,087	55,280	193
Total Telephone	$570,430	$103,085	$103,447	$362

1/ Reflects an increase of .35%.

MONTANA-DAKOTA UTILITIES CO.
OFFICE SUPPLIES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 14

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
Other Gas Supply	$420	$79	$67	($12)
Distribution	60,224	8,209	7,006	(1,203)
Customer Accounting	104,940	19,623	16,746	(2,877)
Customer Service	1,374	96	82	(14)
Sales	11,893	1,949	1,663	(286)
A&G	364,388	73,496	62,721	(10,775)
Total Office Supplies	$543,239	$103,452	$88,285	($15,167)

1/ Reflects a decrease of 14.66%.

MONTANA-DAKOTA UTILITIES CO.
COMPANY CONSUMPTION
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 15

	Per Books - Total			Pro Forma
	Gas Utility	South Dakota	Pro Forma	Adjustment
Distribution	$185,800	$14,703	$18,436	$3,733
Customer Accounting	57,729	6,147	7,780	1,633
Sales	10,082	863	1,092	229
A&G	74,928	15,722	17,099	1,377
Total	$328,539	$37,435	$44,407	$6,972

	Per Books - Electric			Pro Forma
	Gas Utility	South Dakota	Pro Forma	Adjustment
Distribution	$60,579	$655	$655	$0
Customer Accounting	23,845	0	0	0
Sales	3,875	0	0	0
A&G	50,236	10,541	10,541	0
Total Electric	$138,535	$11,196	$11,196	$0

	Per Books - Gas			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
Distribution	$125,221	$14,048	$17,781	$3,733
Customer Accounting	33,884	6,147	7,780	1,633
Sales	6,207	863	1,092	229
A&G	24,692	5,181	6,558	1,377
Total Gas	$190,004	$26,239	$33,211	$6,972

1/ Reflects an increase of 26.57%.

MONTANA-DAKOTA UTILITIES CO.
UNCOLLECTIBLE ACCOUNTS
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 16

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
Distribution	$362	$188	$0	($188)
Customer Accounting	604,262	139,486	209,033	69,547
Total Uncollectible Accounts	$604,624	$139,674	$209,033	$69,359

1/ Based on 5 year average of write-offs to pro forma revenues.

MONTANA-DAKOTA UTILITIES CO.
COMPUTER RENTAL
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 17

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
Customer Accounting	$130,837	$24,702	$30,433	$5,731
A&G	75,059	15,751	19,503	3,752
Total Computer Rental	$205,896	$40,453	$49,936	$9,483

1/ Increase reflects cost of adding a new Geographic Information System server.

MONTANA-DAKOTA UTILITIES CO.
INDUSTRY DUES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 18

	Per Books South Dakota	Pro Forma	Pro Forma Adjustment
American Gas Association 1/	$8,731	$8,174	($557)
Black Hills Community Economic Development, Inc.	249	249	0
Chamber of Commerce - Belle Fourche	499	499	0
Chamber of Commerce-Deadwood	250	250	0
Chamber of Commerce-Lead Area	150	150	0
Chamber of Commerce-Rapid City Area	6,790	6,790	0
Chamber of Commerce-Spearfish	599	599	0
Chamber of Commerce-Sturgis	574	574	0
Energy Safety Association	1,103	1,103	0
Midwest Energy Association	2,147	2,147	0
NARUC	204	204	0
Rapid City Area Economic Development Corp.	3,500	3,500	0
United Telecom Council	350	350	0
Other	17,802	0	(17,802)
	$42,948	$24,589	($18,359)

1/ Pro Forma reflects 2004 dues, adjusted to eliminate 2.00% for lobbying.

MONTANA-DAKOTA UTILITIES CO.
ADVERTISING EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 19

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma	Adjustment
Informational	$57,417	$12,081	$12,081	($0)
Promotional	89,324	26,495		(26,495)
Institutional	157,980	5,647	5,499 1/	(148)
Total	$304,721	$44,223	$17,580	($26,643)

1/ Reflect reclassification of amount recorded in incorrect account.

MONTANA-DAKOTA UTILITIES CO.
REGULATORY COMMISSION EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 20

	South Dakota		Pro Forma
	Per Books	Pro Forma 1/	Adjustment
A&G	$1,869	$156,306	$154,437

1/ Reflects three year amortization of rate case expense.

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION STUDY EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 21

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
A&G	$0	$0	$3,050	$3,050

1/ Reflects 5 year amortization of depreciation study expenses.

MONTANA-DAKOTA UTILITIES CO.
ALL OTHER O&M
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003

	Per Books Other O&M	Items Adjusted Individually	All Other O&M
Other Gas Supply	$66,813	$59,791	$7,022
Distribution	2,719,198	2,665,197	54,001
Customer Accounting	1,446,693	1,362,210	84,483
Customer Service	49,845	46,539	3,306
Sales	273,956	255,317	18,639
A&G	2,708,304	2,235,918	472,386
Total Other O&M	$7,264,809	$6,624,972	$639,837

MONTANA-DAKOTA UTILITIES CO.
ITEMS ADJUSTED INDIVIDUALLY
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003

Function	Per Books	Cost of Gas	Labor	Benefits	Insurance	Contract Labor	Vehicles & Work Equip.	Postage	Telephone
Cost of Gas	$34,335,947	($34,335,947)							
Other Gas Supply	66,813		($59,059)			($582)	($71)		
Distribution	2,719,198		(1,984,680)			(379,312)	(237,562)	($5,451)	($35,092)
Customer Accounting	1,446,693		(879,997)			(134,183)	(28,806)	(121,097)	(8,169)
Customer Service & Information	49,845		(32,087)			(5)	(2,270)	0	0
Sales	273,956		(213,377)			(484)	(6,746)	(666)	(4,737)
Administrative and General	2,708,304		(864,379)	($690,769)	($255,242)	(176,520)	(5,576)	(32,912)	(55,087)
Total Other O&M	7,264,809	0	(4,033,579)	(690,769)	(255,242)	(691,086)	(281,031)	(160,126)	(103,085)
Total O&M	$41,600,756	($34,335,947)	($4,033,579)	($690,769)	($255,242)	($691,086)	($281,031)	($160,126)	($103,085)

DOCKET NO. _____
RULE 20:10:13:81
STATEMENT H
SCHEDULE H-1
PAGE 20 OF 21

MONTANA-DAKOTA UTILITIES CO.
ITEMS ADJUSTED INDIVIDUALLY
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2003

Function	Office Supplies	Company Consumption	Uncollectible Accounts	Computer Rental	Industry Dues	Advertising	Regulatory Commission Expense	All Other O&M
Cost of Gas								$0
Other Gas Supply	($79)							7,022
Distribution	(8,209)	($14,703)	($188)					54,001
Customer Accounting	(19,623)	(6,147)	(139,486)	($24,702)				84,483
Customer Service & Information	(96)					($12,081)		3,306
Sales	(1,949)	(863)				(26,495)		18,639
Administrative and General	(73,496)	(15,722)		(15,751)	($42,948)	(5,647)	($1,869)	472,386
Total Other O&M	(103,452)	(37,435)	(139,674)	(40,453)	(42,948)	(44,223)	(1,869)	639,837
Total O&M	($103,452)	($37,435)	($139,674)	($40,453)	($42,948)	($44,223)	($1,869)	$639,837

DOCKET NO. _____
RULE 20:10:13:81
STATEMENT H
SCHEDULE H-1
PAGE 21 OF 21

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS – GAS UTILITY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003

Please see Rule 20:10:13:80, Schedule H, page 1 and Rule 20:10:13:81, Schedule H-1, page 3 for the cost of gas for the twelve months ending December 31, 2003.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003

Please see the following pages:

Advertising — Please see pages 2-4 for samples of advertising and Rule 20:10:13:81, Statement H, Schedule H-1, page 16 for the advertising expenses.

Benefits — Please see Rule 20:10:13:81, Statement H, Schedule H-1, page 5 for the detail of benefits.

Regulatory Commission Expense — Please see Rule 20:10:13:81, Statement H, Schedule H-1, page 17 for the regulatory commission expense.

SNIFFASAURUS



Knowledge plus care is safety.

For safety's sake, let others in your family scratch the flame and sniff, too.

If you ever smell this odor, leave the house and call us from a neighbor's telephone. Do not operate any light switches or electrical equipment.

Natural gas is really odorless. The odor you sniffed when you scratched the flame is a chemical added to natural gas so you can easily recognize the escaping gas.

Natural gas has a safety record we can all be proud of. We are working, with your help, to keep it that way!

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

1-800-MDU-FAST

ACCOUNT 909
INFORMATIONAL



Because it's a *natural gas home.*

Ask your realtor...most homes will sell faster and for more money if it has natural gas. Why?

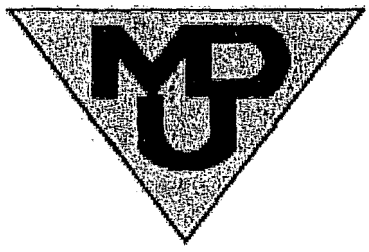
- *Natural gas* heat costs less than other forms of pollution-free energy and natural gas is warm. Some forced-air heating systems deliver air that actually feels cool With natural gas, you get warmth, economy and comfort.
- *Natural gas* water heaters will supply all the hot water you want whenever you want it while saving you money. Generally, natural gas water heating is less than half the operating cost of a flameless model.
- *Natural gas* ranges are the only type of range that gives you instant heat plus the infinite temperature control for better cooking.
- *Natural gas* dryers offer additional operation savings over flameless models.

Four good reasons why natural gas homes sell more quickly...ask your realtor.

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve℠

ACCOUNT 913
PROMOTIONAL

DOCKET NO. RULE 20:10:13:83
STATEMENT H
SCHEDULE H-3
PAGE 3 OF 4



MONTANA-DAKOTA

UTILITIES CO.

A Division of MDU Resources Group, Inc.

In the Community to Serve™

ACCOUNT 930.1
INSTITUTIONAL

MONTANA-DAKOTA UTILITIES CO.
INTERCOMPANY TRANSACTIONS
TWELVE MONTHS ENDING DECEMBER 31, 2003

Williston Basin Interstate Pipeline Co.	$45,525,081
Bitter Creek Pipelines, LLC	1,190,596
Pioneer Construction, Inc.	7,157
Prairielands Energy Marketing, Inc.	9,843,445
Knife River	1,081,736
JTL Group Inc.	19,323
Empire Sand & Gravel Co	794
Fidelity Exploration & Production	18,282,781
Rocky Mountain Contractors, Inc.	697
Highline Equipment Inc.	15,887
Wagner Smith Equipment Co	10,643
Total	$75,978,139

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF CURRENT AND PRO FORMA REVENUES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003

	Per Books	Pro Forma Adjustments	Pro Forma Revenue
Sales			
Residential	$23,626,622	$7,426,696	$31,053,318
Firm General 1/	16,357,688	6,342,887	22,700,575
Air Force	2,283,008	989,398	3,272,406
Small Interruptible	215,388	(20,334)	195,054
Large Interruptible	399,602	118,918	518,520
Unbilled Revenue	1,319,327	(1,319,327)	0
Total Sales	$44,201,635	$13,538,238	$57,739,873
Transportation			
Small Interruptible	210,676	268	210,944
Large Interruptible	159,118	(45,278)	113,840
Unbilled Revenue	(6,609)	6,609	0
Total Transportation	$363,185	($38,401)	$324,784
Total Sales and Transportation	$44,564,820	$13,499,837	$58,064,657
Other Revenue			
Miscellaneous Service Revenue	$27,095	$0	$27,095
Rent from Property	136,285	0	136,285
Other Revenue	53,241	0	53,241
Late Payment Revenues	0	47,709	47,709
Total Other Revenue	$216,621	$47,709	$264,330
Total Operating Revenue	$44,781,441	$13,547,546	$58,328,987

1/ Includes firm contract revenues.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF REVENUES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003
PRO FORMA 2004

	Per Books			Per Books @ Current Rates 2/			Normalized		
Rate Reporting Class	Customers 1/	Dk	Revenue	Customers 1/	Dk	Revenue	Customers 1/	Dk	Revenue
Sales									
Residential									
Residential	36,459	3,048,371	$23,626,622	36,459	3,048,371	$28,966,732	36,459	3,164,381	$29,942,493
Total Residential	36,459	3,048,371	23,626,622	36,459	3,048,371	28,966,732	36,459	3,164,381	29,942,493
Air Force									
Interruptible	1	537,378	2,283,008	1	537,378	3,068,493	1	573,102	3,272,406
Total Air Force	1	537,378	2,283,008	1	537,378	3,068,493	1	573,102	3,272,406
Firm General									
Firm General	4,870	2,720,670	16,357,688	4,870	2,720,670	21,382,249	4,870	2,790,159	21,941,913
Total Firm General	4,870	2,720,670	16,357,688	4,870	2,720,670	21,382,249	4,870	2,790,159	21,941,913
Interruptible									
Small Interruptible	10	35,076	215,388	10	35,076	266,160	10	35,076	266,160
Large Interruptible	1	86,205	399,602	1	86,205	509,202	1	88,690	523,829
Total Interruptible	11	121,281	614,990	11	121,281	775,362	11	123,766	789,989
Total Sales	41,341	6,427,700	42,882,308	41,341	6,427,700	54,192,836	41,341	6,651,408	55,946,801
Transportation									
Small Interruptible	28	344,377	210,676	28	344,377	193,839	28	319,325	193,839
Large Interruptible	12	613,766	159,118	12	613,766	137,437	12	605,946	136,052
Total Transportation	40	958,143	369,794	40	958,143	331,276	40	925,271	329,891
Total Sales & Transportation	41,381	7,385,843	$43,252,102	41,381	7,385,843	$54,524,112	41,381	7,576,679	$56,276,692

DOCKET NO. _____
RULE 20:10:13:8
STATEMENT I
PAGE 2 OF 10

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF REVENUES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003
PRO FORMA 2004

	Annualized			Pro Forma 2004		
Rate Reporting Class	Customers 1/	Dk	Revenue	Customers 1/	Dk	Revenue
Sales						
Residential						
Residential	37,153	3,213,222	$30,416,622	37,933	3,280,458	$31,053,318
Total Residential	37,153	3,213,222	30,416,622	37,933	3,280,458	31,053,318
Air Force						
Interruptible	1	573,102	3,272,406	1	573,102	3,272,406
Total Air Force	1	573,102	3,272,406	1	573,102	3,272,406
Firm General						
Firm General	4,931	2,805,336	22,071,501	5,093	2,880,332	22,700,575
Total Firm General	4,931	2,805,336	22,071,501	5,093	2,880,332	22,700,575
Interruptible						
Small Interruptible	10	35,076	266,160	7	25,747	195,054
Large Interruptible	1	88,690	523,829	1	87,788	518,520
Total Interruptible	11	123,766	789,989	8	113,535	713,574
Total Sales	42,096	6,715,426	56,550,518	43,035	6,847,427	57,739,873
Transportation						
Small Interruptible	28	344,377	193,839	30	381,174	210,944
Large Interruptible	12	605,946	136,052	8	534,690	113,840
Total Transportation	40	950,323	329,891	38	915,864	324,784
Total Sales & Transportation	42,136	7,665,749	$56,880,409	43,073	7,763,291	$58,064,657

1/ Average monthly customers.
2/ Rates effective with service rendered on and after 12/02/03, Docket No. NG02-011.
June 1, 2004 Purchased Gas Adjustment reflecting weighted seasonal demand and annual gas commodity.

DOCKET NO. _____
RULE 20:10:13:85
STATEMENT I
PAGE 3 OF 10

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ADJUSTMENT TO REVENUES REFLECTING CURRENT RATES
TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT NO. 1

	Revenue Per Books	Revenues @ Current Rates 1/	Pro Forma Adjustment
Sales			
Residential	$23,626,622	$28,966,732	$5,340,110
Firm General	16,357,688	21,382,249	5,024,561
Air Force	2,283,008	3,068,493	785,485
Small Interruptible	215,388	266,160	50,772
Large Interruptible	399,602	509,202	109,600
Unbilled Revenue	1,319,327	0	(1,319,327)
Total Sales	$44,201,635	$54,192,836	$9,991,201
Transportation			
Small Interruptible	210,676	193,839	(16,837)
Large Interruptible	159,118	137,437	(21,681)
Unbilled Revenue	(6,608)	0	6,608
Total Transportation	$363,186	$331,276	($31,910)
Total Sales & Transportation Revenue	$44,564,821	$54,524,112	$9,959,291

1/ Rates effective with service rendered on and after 12/02/03, Docket No. NG02-011. June 1, 2004 Purchased Gas Adjustment reflecting weighted seasonal demand and annual gas commodity.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ADJUSTMENT TO REVENUES REFLECTING NORMAL WEATHER
TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT NO. 2

	Revenues @ Current Rates		Normalized		Pro Forma
	Dk	Revenue	Dk 1/	Revenue	Adjustment
Sales					
Residential	3,048,371	$28,966,732	3,164,381	$29,942,493	$975,761
Firm General	2,720,670	21,382,249	2,790,159	21,941,913	559,664
Air Force	537,378	3,068,493	573,102	3,272,406	203,913
Small Interruptible	35,076	266,160	35,076	266,160	0
Large Interruptible	86,205	509,202	88,690	523,829	14,627
Total Sales	6,427,700	$54,192,836	6,651,408	$55,946,801	$1,753,965
Transportation					
Small Interruptible	344,377	193,839	319,325	193,839	0
Large Interruptible	613,766	137,437	605,946	136,052	(1,385)
Total Transportation	958,143	$331,276	925,271	$329,891	($1,385)
Total Sales & Transportation Revenue	7,385,843	$54,524,112	7,576,679	$56,276,692	$1,752,580

Residential, Firm General, Air Force and Small Interruptible volumes are adjusted to reflect normal weather.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ADJUSTMENT TO REVENUES REFLECTING ANNUALIZED CUSTOMERS
TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT NO. 3

	Normalized		Annualized		Pro Forma
	Dk	Revenue	Dk 1/	Revenue	Adjustment
Sales					
Residential	3,164,381	$29,942,493	3,213,222	$30,416,622	$474,129
Firm General	2,790,159	21,941,913	2,805,336	22,071,501	129,588
Air Force	573,102	3,272,406	573,102	3,272,406	0
Small Interruptible	35,076	266,160	35,076	266,160	0
Large Interruptible	88,690	523,829	88,690	523,829	0
Total Sales	6,651,408	$55,946,801	6,715,426	$56,550,518	$603,717
Transportation					
Small Interruptible	319,325	193,839	344,377	193,839	0
Large Interruptible	605,946	136,052	605,946	136,052	0
Total Transportation	925,271	$329,891	950,323	$329,891	$0
Total Sales & Transportation Revenue	7,576,679	$56,276,692	7,665,749	$56,880,409	$603,717

1/ Residential and firm volumes are annualized.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ADJUSTMENT TO REVENUES REFLECTING PRO FORMA REVENUES
TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT NO. 4

	Annualized		Pro Forma 2004		Pro Forma
	Dk	Revenue	Dk 1/	Revenue	Adjustment
Sales					
Residential	3,213,222	$30,416,622	3,280,458	$31,053,318	$636,696
Firm General	2,805,336	22,071,501	2,880,332	22,700,575	629,074
Air Force	573,102	3,272,406	573,102	3,272,406	0
Small Interruptible	35,076	266,160	25,747	195,054	(71,106)
Large Interruptible	88,690	523,829	87,788	518,520	(5,309)
Total Sales	6,715,426	$56,550,518	6,847,427	$57,739,873	$1,189,355
Transportation					
Small Interruptible	344,377	193,839	381,174	210,944	17,105
Large Interruptible	605,946	136,052	534,690	113,840	(22,212)
Total Transportation	950,323	$329,891	915,864	$324,784	($5,107)
Total Sales & Transportation Revenue	7,665,749	$56,880,409	7,763,291	$58,064,657	$1,184,248

Reflects changes in customers and volumes occuring in 2004.

MONTANA-DAKOTA UTILITIES CO.
MISCELLANEOUS REVENUES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 5

	Per Books	Pro Forma Adjustments	Pro Forma
Miscellaneous Service Revenue			
Reconnect Fees	$9,276		$9,276
NSF Check Fees	5,350		5,350
Work for Contractors, Municipalities and Others	12,469		12,469
Miscellaneous Service Revenue	$27,095		$27,095
Rent from Property	136,285		136,285
Other Revenue	53,241		53,241
Late Payment Revenues		47,709	47,709
Total Misc. Revenues	$216,621	$47,709	$264,330

MONTANA-DAKOTA UTILITIES CO.
PER BOOKS REVENUE BY CUSTOMER CLASS
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sept 03	Oct 03	Nov 03	Dec 03	Total
Sales													
Residential	$3,039,278	$2,905,256	$3,116,656	$2,618,490	$1,561,119	$1,070,726	$891,467	$718,320	$779,602	$1,267,002	$2,310,464	$3,348,242	$23,626,622
Firm General	1,943,569	1,913,617	2,181,448	1,789,471	1,060,895	842,224	732,546	617,274	589,213	872,445	1,533,506	2,281,479	16,357,687
Air Force	278,783	288,187	317,156	430,970	181,283	126,245	55,089	33,912	28,606	53,984	132,317	356,476	2,283,008
Small Interruptible	26,390	23,515	27,929	25,036	14,603	13,664	17,823	12,470	9,629	11,872	15,692	16,765	215,388
Large Interruptible	39,457	37,359	47,111	48,284	26,782	25,907	28,255	16,688	15,538	29,226	38,913	46,082	399,602
Total Sales	5,327,477	5,167,934	5,690,300	4,912,251	2,844,682	2,078,766	1,725,180	1,398,664	1,422,588	2,234,529	4,030,892	6,049,044	42,882,307
Transportation													
Small Interruptible	16,686	23,893	22,990	21,048	15,306	14,265	11,886	13,791	13,669	16,261	16,077	24,804	210,676
Large Interruptible	17,073	14,674	14,698	17,056	13,716	12,834	12,243	11,095	9,958	10,298	11,993	13,481	159,119
Total Transportation	33,759	38,567	37,688	38,104	29,022	27,099	24,129	24,886	23,627	26,559	28,070	38,285	369,795
Total South Dakota	$5,361,236	$5,206,501	$5,727,988	$4,950,355	$2,873,704	$2,105,865	$1,749,309	$1,423,550	$1,446,215	$2,261,088	$4,058,962	$6,087,329	$43,252,102

DOCKET NO. _____
RULE 20:10:13:85
STATEMENT I
PAGE 9 OF 10

MONTANA-DAKOTA UTILITIES CO.
REVENUES AT PROPOSED RATES

Please see Rule 20:10:13:98, Statement O, page 1, for the revenues at proposed rates by customer class.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF DEPRECIATION EXPENSE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003

Function	2003 Per Books	Pro Forma 1/	Pro Forma Adjustment
Distribution	$1,439,017	$1,306,376	($132,641)
General	187,348	310,772	123,424
General Intangible	1,122	749	(373)
Common	67,232	96,858	29,626
Common Intangible	$120,865	$127,592	6,727
CWIP in Service		2/	2/
Total	$1,815,584	$1,842,347	$26,763

Pro Forma Adjustment to Accumulated Reserve $2,298,170

1/ Average Annual depreciation expense on pro forma plant in service.
2/ Included in the above functions.

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION RATES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003
PRO FORMA ADJUSTMENT NO. 22

Acct. No.	Account	Pro Forma Average Plant 1/	Depreciation Rate	Annual Depreciation	Accumulated Reserve
	Distribution Plant				
374.1	Land	$29,922			
374.2	Rights of Way	8,609	0.75%	$65	$65
375	Structures & Improvements	39,785	3.24%	1,289	1,289
376	Mains	19,793,042	3.15%	623,481	623,481
378	Meas. & Reg. Equip.-General	291,533	3.31%	9,650	9,650
379	Meas. & Reg. Equip.-City Gate	78,548	4.33%	3,401	3,401
380	Services	5,858,971	7.03%	411,886	411,886
381	Positive Meters	6,448,079	3.19%	205,694	205,694
383	Service Regulators	902,434	2.87%	25,900	25,900
385	Ind. Meas. & Reg. Station Eqpt.	63,429	3.77%	2,391	2,391
386.2	Other Property on Cust. Premise	170,931	3.70%	6,324	6,324
387.1	Cathodic Protection Equip.	73,750	5.75%	4,241	4,241
387.2	Other Distribution Equip.	86,342	1.42%	1,226	1,226
	Total Distribution Plant	$33,845,375		$1,295,548	$1,295,548
	General Plant				
389	Land	$580,983			
390	Structures and Improvements	3,769,782	4.61%	$173,787	$173,787
391.1	Furniture and Fixtures	229,883	4.97%	11,425	11,425
391.3	Computer Equip. - PC	256,064	26.02%	66,628	66,628
392.1	Trans. Equip., Non-Unitized	35,859	4.36% 2/		1,563
392.2	Trans. Equip., Unitized	1,993,959	21.13% 2/		421,324
393	Stores Equipment	45,724	2.49%	1,139	1,139
394.1	Tools,Shop&Gar. Eq.-Non-Un.	357,382	6.62%	23,659	23,659
394.2	Tools,Shop&Gar. Eq.-Unitized	24,072	2.40% 2/		578
394.3	Vehicle Maintenance Equip.	7,627	5.78%	441	441
394.4	Vehicle Refueling Equip.	66,386	4.72%	3,133	3,133
395	Laboratory Equipment	19,588	7.67%	1,502	1,502
396.1	Power Operated Equip.	183,732	5.76% 2/		10,583
396.2	Work Equipment Trailers	1,540,151	0.00% 2/		0
397.1	Radio Comm. Equip.-Fixed	105,416	7.37%	7,769	7,769
397.2	Radio Comm. Equip.-Mobile	126,620	7.34%	9,294	9,294
397.3	General Tele. Comm. Equip.	25,321	9.88%	2,502	2,502
397.8	Network Equipment	23,831	26.26%	6,258	6,258
398	Miscellaneous Equipment	9,611	1.27%	122	122
	Total General Plant	$9,401,991		$307,659	$741,707
303	Intangible Plant - General	$138,705	0.54% 3/	$749	$749

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION RATES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003
PRO FORMA ADJUSTMENT NO. 22

Acct. No.	Account	Pro Forma Average Plant 1/	Depreciation Rate	Annual Depreciation	Accumulated Reserve
	Common Plant				
389	Land	$35,977			
390	Structures and Improvements	469,671	2.93%	$13,761	$13,761
391.1	Furniture and Fixtures	129,892	4.95%	6,430	6,430
391.2	Computer Equip.- Bull/AS400	1,218	1.52%	19	19
391.3	Computer Equip. - PC	277,345	23.29%	64,594	64,594
391.4	Computer Equip. - EMS	450	0.00%	0	0
391.5	Computer Equip. - Other	7,226	0.46% 4/	18	18
392.1	Trans. Equip., Non-Unitized	1,870	0.00% 2/		0
392.2	Trans. Equip., Unitized	63,030	13.33% 2/		8,402
392.3	Aircraft	377,806	5/		13,373
393	Stores Equipment	323	2.80%	9	9
394.1	Tools, Shop & Gar. Equip.	2,285	6.11%	140	140
394.3	Vehicle Maint. Equip.	7,850	4.75%	373	373
394.4	Vehicle Refueling Equip.	8,388	4.38%	367	367
397.1	Radio Comm. Equip.-Fixed	13,621	4.99%	680	680
397.2	Radio Comm. Equip.-Mobile	21,960	4.08%	896	896
397.3	General Tele. Comm. Equip.	32,994	8.72%	2,877	2,877
397.5	Supervisory & Tele. Equip.	179	0.35%	1	1
397.8	Network Equipment	31,577	17.95%	5,668	5,668
398	Miscellaneous Equipment	35,405	2.41%	853	853
	Total Common Plant	$1,519,067		$96,686	$118,461
303	Intangible Plant - Common	$1,355,918	9.41% 3/	$127,592	$127,592
	CWIP in Service 6/				
	Distribution	$282,721	3.83%	$10,828	$10,828
	General	40,065	7.77%	3,113	3,113
	Common	2,076	8.28%	172	172
	Total CWIP	$324,862		$14,113	$14,113
	Total Gas Plant in Service	$46,585,918		$1,842,347	$2,298,170

1/ See Rule 20:10:13:54.
2/ Charged to a clearing account.
3/ Amortized.
4/ Reflects depreciation on pro forma plant addition only as account was previously fully depreciated.
5/ Amortized and charged to a clearing account.
6/ Composite rates by function.

MONTANA DAKOTA UTILITIES CO.
DEPRECIATION AND AMORTIZATION EXPENSES

See Pages 5 through 7 for Montana-Dakota's depreciation rates as set forth in a study performed by AUS Consultants as of December 31, 2001 for gas and common plant.

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	Distribution Plant						
374.20	Rights of Way	89,641.04	2.58%	2,312.74	0.75%	672.31	-1,640.43
375.00	Distr. Meas & Reg Station Structures	521,210.22	2.40%	12,509.05	3.24%	16,887.21	4,378.16
	Mains						
376.10	Mains-Steel	33,849,069.40	4.05%	1,370,887.31	2.89%	978,238.11	-392,649.20
376.20	Mains-Plastic	44,012,975.20	4.05%	1,782,525.50	3.35%	1,474,434.67	-308,090.83
376.30	Mains-Valves	391,503.88	4.05%	15,855.91	3.78%	14,798.85	-1,057.06
376.40	Mains-Manholes	69,919.29	4.05%	2,831.73	3.25%	2,272.38	-559.35
376.50	Mains-Bridge & River Crossings	10,685.81	4.05%	432.78	3.47%	370.80	-61.98
	Total Mains	78,334,153.58	4.05%	3,172,533.23	3.15%	2,470,114.81	-702,418.42
378.00	Meas & Reg Station Equip-General	1,367,333.67	2.30%	31,448.67	3.31%	45,258.74	13,810.07
379.00	Meas & Reg Station Equip-City Gate	1,009,136.85	2.74%	27,650.35	4.33%	43,695.63	16,045.28
	Services						
380.10	Services-Steel	7,683,869.79	7.60%	583,974.10	7.14%	548,628.30	-35,345.80
380.20	Services-Plastic	24,580,506.89	7.60%	1,868,118.52	6.97%	1,713,261.33	-154,857.19
380.30	Farm & Fuel Lines	212,340.42	7.60%	16,137.87	9.33%	19,811.36	3,673.49
	Total Services	32,476,717.10	7.60%	2,468,230.49	7.03%	2,281,700.99	-186,529.50
381.00	Meters	30,462,008.09	2.58%	785,919.81	3.19%	971,738.06	185,818.25
383.00	Service Regulators	4,296,861.63	2.37%	101,835.62	2.87%	123,319.93	21,484.31
385.00	Industrial Meas. & Reg. Station Equipment	578,200.01	1.91%	11,043.62	3.77%	21,798.14	10,754.52
	MISCELLANEOUS EQUIPMENT						
386.10	Miscellaneous Property on Customers Premise	1,679.84	9.35%	157.07	5.19%	87.18	-69.89
386.20	CNG Refueling station	432,811.48	9.35%	40,467.87	3.70%	16,014.02	-24,453.85
	TOTAL Account 386	434,491.32	9.35%	40,624.94	3.71%	16,101.20	-24,523.74
	OTHER EQUIPMENT						
387.10	Cathodic Protection Equipment	1,450,657.25	5.21%	75,579.24	5.75%	83,412.79	7,833.55
387.20	Other Distribution Equipment	557,183.52	5.21%	29,029.26	1.42%	7,912.01	-21,117.25
	TOTAL Account 387	2,007,840.77	5.21%	104,608.50	4.55%	91,324.80	-13,283.70
	TOTAL Distribution Plant	151,577,594.28	4.46%	6,758,717.02	4.01%	6,082,611.82	-676,105.20
	General Plant						
390.00	General Structures	1,922,983.06	2.34%	44,997.80	4.61%	88,649.52	43,651.72
	OFFICE FURNITURE & EQUIPMENT						
391.10	Office Furniture & Equipment	544,274.64	4.05%	22,043.12	4.97%	27,033.65	4,990.53
391.30	Computer Equipment - PC	780,994.56	12.50%	97,624.32	26.02%	203,214.78	105,590.46
	TOTAL Account 391	1,325,269.20	9.03%	119,667.44	17.37%	230,248.43	110,580.99
	TRANSPORTATION EQUIPMENT						
392.10	Transportation Equipment (Trailers)	147,186.67	5.74%	8,448.51	4.36%	6,417.34	-2,031.17
392.20	Transportation Equipment (Cars & Trucks)	6,080,561.05	5.74%	349,024.20	21.13%	1,284,822.55	935,798.35
	TOTAL Account 392	6,227,747.72	5.74%	357,472.71	20.73%	1,291,239.89	933,767.18
393.00	Stores Equipment	186,729.06	0.90%	1,680.56	2.49%	4,658.15	2,977.59
	TOOLS, SHOP & GARAGE EQ.						
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,495,421.95	3.57%	89,086.56	6.62%	165,153.11	76,066.55
394.20	Tools, Shop & Garage Equip. (Unitized)	299,809.93	4.83%	14,480.82	2.40%	7,200.70	-7,280.12
394.30	Vehicle Maintenance Equipment	31,176.58	4.21%	1,312.53	5.78%	1,803.27	490.74
394.40	Vehicle Refueling Equipment	361,344.00	9.35%	33,785.66	4.72%	17,065.14	-16,720.52
	TOTAL Account 394	3,187,752.46	4.35%	138,665.57	6.00%	191,222.22	52,556.65
395.00	Laboratory Equipment	271,033.04	2.32%	6,287.97	7.67%	20,800.98	14,513.01

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	POWER OPERATED EQUIPMENT						
396.10	Work Equipment (Trailers)	293,543.45	4.83%	14,178.15	5.76%	16,908.10	2,729.95
396.20	Power Operated Equipment	4,081,768.33	4.83%	197,149.41	0.00%	0.00	-197,149.41
	TOTAL Account 396	4,375,311.78	4.83%	211,327.56	0.39%	16,908.10	-194,419.46
	COMMUNICATION EQUIPMENT						
397.10	Radio Communication Equip. (Fixed)	481,655.16	3.67%	17,676.74	7.37%	35,510.67	17,833.93
397.20	Radio Communication Equip. (Mobile)	401,528.27	3.67%	14,736.09	7.34%	29,468.63	14,732.54
397.30	General Telephone Communication Equip.	90,517.88	6.56%	5,937.97	9.88%	8,941.08	3,003.11
397.50	Supervisory & Telemetering Equip.	124,167.15	6.67%	8,281.95	0.25%	310.92	-7,971.03
397.60	SCADA System	30,894.36	15.07%	4,655.78	0.00%	0.00	-4,655.78
397.80	Network Equipment	30,337.55	12.50%	3,792.19	26.26%	7,967.96	4,175.77
	TOTAL Account 397	1,159,100.37	4.75%	55,080.72	7.09%	82,199.26	27,118.54
398.00	Miscellaneous Equipment	145,269.53	0.59%	857.09	1.27%	1,851.12	994.03
	Sub-Total (General Plant) Amortization	**5,494,159.10**	**4.09%**	**224,615.03**	**5.97%**	**327,765.38**	**103,150.35**
	TOTAL General Plant	18,801,196.22	4.98%	936,037.42	10.25%	1,927,777.67	991,740.25
	TOTAL Depreciable Plant	170,378,790.50	4.52%	7,694,754.44	4.70%	8,010,389.49	315,635.05
	NON-DEPRECIABLE PLANT						
374.10	Land (Distribution)	108,919.96					
389.00	Land & Land Rights (General)	301,148.77					
	Total Land	410,068.73					
	INTANGIBLE PLANT						
303.00	Miscellaneous Intangible Plant	477,529.69					
	Total Intangible Plant	477,529.69					
	TOTAL Non-Depreciable Plant	887,598.42					
	TOTAL Plant in Service	171,266,388.92					

Montana-Dakota Utilities Company
Common Plant

Summary or Original Cost of Utility Plant in Service as of December 31, 2001
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/01 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates Rate % (f)	Proposed Rates Annual Accrual (g)	Net Change Depr. Exp. (h)
	DEPRECIABLE PLANT						
	General Plant						
390.0	General Structures	18,048,459.30	3.76%	678,622.07	2.93%	528,819.86	-149,802.21
	OFFICE FURNITURE & EQUIPMENT						
391.1	Office Furniture & Equipment	3,716,416.91	1.48%	55,002.97	4.95%	184,032.14	129,029.17
391.2	Computer Equipment - Honeywell	93,392.30	14.17%	13,233.69	1.52%	1,416.58	-11,817.11
391.3	Computer Equipment - PC	4,212,743.17	12.50%	526,592.90	23.29%	981,147.88	454,554.98
391.5	Computer Equipment - Other	820,399.57	26.51%	217,487.93	0.46%	3,797.58	-213,690.35
	TOTAL Account 391	8,842,951.95	9.19%	812,317.49	13.24%	1,170,394.18	358,076.69
	TRANSPORTATION EQUIPMENT						
392.1	Transportation Equipment (Trailers)	251,165.84	5.74%	14,416.92	0.00%	0.00	-14,416.92
392.2	Transportation Equipment (Cars & Trucks)	4,429,701.58	5.74%	254,264.87	13.33%	590,479.22	336,214.35
	TOTAL Account 392	4,680,867.42	5.74%	268,681.79	12.61%	590,479.22	321,797.43
393.0	Stores Equipment	47,385.55	3.36%	1,592.15	2.80%	1,327.61	-264.54
	TOOLS, SHOP & GARAGE EQ.						
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	235,026.00	3.44%	8,084.89	6.11%	14,362.50	6,277.61
394.3	Vehicle Maintenance Equipment	102,746.14	4.46%	4,582.48	4.75%	4,877.05	294.57
394.4	Vehicle Refueling Equipment	838,830.77	8.42%	70,629.55	4.38%	36,709.31	-33,920.24
	TOTAL Account 394	1,176,602.91	7.08%	83,296.92	4.76%	55,948.86	-27,348.06
396.2	Power Operated Equipment	157,572.62	4.83%	7,610.76	2.69%	4,238.70	-3,372.06
	COMMUNICATION EQUIPMENT						
397.1	Radio Communication Equip. (Fixed)	646,187.02	4.33%	27,979.90	4.99%	32,241.83	4,261.93
397.2	Radio Communication Equip. (Mobile)	1,285,023.00	6.68%	85,839.54	4.08%	52,474.26	-33,365.28
397.3	General Telephone Communication Equip.	779,821.23	10.62%	82,817.01	8.72%	68,036.36	-14,780.65
397.5	Supervisory & Telemetering Equip.	48,295.94	0.59%	284.95	0.35%	170.00	-114.95
397.8	Network Equipment	824,948.21	12.50%	103,118.53	17.95%	148,037.04	44,918.51
	TOTAL Account 397	3,584,275.40	8.37%	300,039.93	8.40%	300,959.49	919.56
398.0	Miscellaneous Equipment	592,894.94	2.51%	14,881.66	2.41%	14,291.82	-589.84
	Sub-Total (General Plant) Amortization	**10,031,367.58**	**6.83%**	**685,535.25**	**5.60%**	**561,774.08**	**-123,761.17**
	TOTAL General Plant	37,131,010.09	5.84%	2,167,042.77	7.18%	2,666,459.74	499,416.97
	TOTAL Depreciable Plant	37,131,010.09	5.84%	2,167,042.77	7.18%	2,666,459.74	499,416.97
	Amortizable Plant						
392.3	Aircraft Equipment	1,024,349.51					
	TOTAL Amortizable Plant	1,024,349.51					
	NON-DEPRECIABLE PLANT						
389.0	Land & Land Rights (General)	1,547,408.83					
	Total Land	1,547,408.83					
	INTANGIBLE PLANT						
303.0	Miscellaneous Intangible Plant	13,553,859.20					
	Total Intangible Plant	13,553,859.20					
	TOTAL Non-Depreciable Plant	15,101,268.03					
	TOTAL Plant in Service	53,256,627.63					

MONTANA-DAKOTA UTILITIES CO.
RECONCILIATION OF DEPRECIABLE GAS PLANT
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Balance @ 12/30/02	Balance @ 12/30/03	Average Balance
Depreciable Plant			
Distribution	$30,882,702	$32,770,414	$31,826,558
General	5,551,798	5,020,683	5,286,241
General - Amortized	135,079	138,705	136,892
	$36,569,579	$37,929,802	$37,249,691
Depreciable Plant Charged to a Clearing Account			
Transportation Equipment	$1,946,431	$1,885,421	$1,915,926
Tools, Shop & Garage Equipment - Unitized	57,875	24,072	40,973
Power Operated Equipment	96,572	96,572	96,572
Work Equipment	1,184,412	1,540,151	1,362,282
	$3,285,290	$3,546,216	$3,415,753
Non-Depreciable Plant			
Distribution	$30,306	$29,922	$30,114
General	582,013	580,983	581,498
	$612,319	$610,905	$611,612
Common Plant in Service - Gas			
Depreciable	$1,021,160	$984,043	$1,002,602
Charged to Clearing Account	135,070	435,007	285,038
Depreciable - Amortized	1,073,230	1,240,928	1,157,079
Non-Depreciable	31,426	35,977	33,701
	$2,260,886	$2,695,955	$2,478,420
Total Gas Plant in Service	$42,728,074	$44,782,878	$43,755,476

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION EXPENSE CHARGED TO OTHER THAN PRESCRIBED DEPRECIATION AND AMORTIZATION EXPENSE

The Company charges all depreciation and amortization expense to prescribed accounts, with the exception of the following:

1. Depreciation of transportation and work equipment in FERC plant accounts 392 and 396 are charged to FERC clearing account 184 through cost center 184.00.
2. Depreciation of aircraft in FERC plant account 392 is charged to FERC clearing account 184 through cost center 184.01.
3. Depreciation of a portion of general plant structures in FERC account 390 is charged to FERC account 416 for merchandise operations.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ADJUSTMENTS TO PER BOOKS TAXABLE INCOME
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003

	Reference	Pro Forma Adjustment
Operating Income		
Current Income Taxes		
Interest Expense Annualization 1/	Statement K, Page 7	($60,189)
Income Taxes on Pro Forma Adjustments	Statement K, Page 8	111,302
Elimination of Closing/Filing	Statement K, Page 9	46,139
Tax Depreciation on Plant Additions 1/	Statement K, Page 14	171,814
Deferred Income Taxes		
Elimination of Closing/Filing from Deferred Income Taxes	Statement K, Page 9	(44,463)
Deferred Income Taxes on Plant Additions - Current	Statement K, Page 14	60,135
Rate Base		
Accumulated Def. Inc. Tax - Plant additions and normalization	Statement K, Page 16	87,245
Accumulated Investment Tax Credits	Statement K, Page 16	(13,430)

1/ Amount is shown before income tax effect.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Utility				Total
	Gas	Electric	Total	Non-Utility	Company
Operating Revenue	$237,207,834	$178,561,980	$415,769,814		$415,769,814
Non-Utility Income (before income taxes)				$2,905,254	2,905,254
Total Revenue	$237,207,834	$178,561,980	$415,769,814	$2,905,254	$418,675,068
Operating Expense:					
O&M Expense	217,820,526	114,966,977	332,787,503		332,787,503
Depreciation Expense	8,477,139	20,150,400	28,627,539		28,627,539
Taxes Other than Income	4,647,527	7,683,325	12,330,852		12,330,852
Total Operating Expense	230,945,192	142,800,702	373,745,894		373,745,894
Operating Income	6,262,642	35,761,278	42,023,920	2,905,254	44,929,174
Interest Expense	3,265,632	8,013,254	11,278,886		11,278,886
Book Taxable Income before Adjustments	2,997,010	27,748,024	30,745,034	2,905,254	33,650,288
Deductions and Adjustments to Book Income:					
Tax Deductions 1/	12,715,396	1,709,317	14,424,713	2,538,538	16,963,251
Preferred Dividend Paid Deduction	52,184	117,611	169,795		169,795
Total Deductions and Adjustments	12,767,580	1,826,928	14,594,508	2,538,538	17,133,046
Taxable Income - Before State Income Tax	(9,770,570)	25,921,096	16,150,526	366,716	16,517,242
Less: Deductible State Income Taxes	(582,346)	1,474,929	892,583	20,853	913,436
Federal Taxable Income	(9,188,224)	24,446,167	15,257,943	345,863	15,603,806
Federal Income Taxes @ 35%	(3,215,879)	8,556,158	5,340,279	121,050	5,461,329
Credits and Adjustments	(7,532)	(11,320)	(18,852)	1,434,450	1,415,598
State Income Taxes	(582,346)	1,474,929	892,583	20,853	913,436
Federal and State Income Taxes	(3,805,757)	10,019,767	6,214,010	1,576,353	7,790,363
Rounding and Prior Year's Adjustment	(318,854)	(793,855)	(1,112,709)	22,593	(1,090,116)
Total Federal and State Income Taxes	($4,124,611)	$9,225,912	$5,101,301	$1,598,946	$6,700,247

DOCKET NO. _____
RULE 20:10:13:88
STATEMENT K
PAGE 2 OF 16

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
TAX DEDUCTIONS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Utility				Total
1900 Account M-1's	Gas	Electric	Total	Non-Utility	Company
Management Incentive Compensation	($191,611)	($228,282)	($419,893)	($11,368)	($431,261)
Pension Expense	657,311	549,260	1,206,571		1,206,571
Sundry Reserves	914	2,060	2,974		2,974
Property Insurance Adjustment	214,996	150,553	365,549		365,549
Bad Debt Expense	(82,083)	4,732	(77,351)	(6,936)	(84,287)
Accrued Vacation	(201,310)	(172,852)	(374,162)		(374,162)
Capitalized Overheads	(104,056)		(104,056)		(104,056)
Customer Advances	148,585	100,398	248,983		248,983
Restricted Stock Bonus Plan	(241,823)	(363,441)	(605,264)		(605,264)
Supplemental Income Security Plan				(1,507,134)	(1,507,134)
FAS 106 - OPRB	4,836	6,095	10,931	1,295	12,226
Deferred Compensation	(226,864)	(340,958)	(567,822)		(567,822)
BOD Retirement	14,173	21,301	35,474		35,474
Demand Charges	345,925		345,925		345,925
PCB related income	11,720		11,720		11,720
2820 Account M-1's					
Liberalized Depreciation and Other Property Timing Differences	(394,426)	2,336,179	1,941,753	114,723	2,056,476
Contributions in Aid of Construction	(147,896)	(61,531)	(209,427)		(209,427)
2830 Account M-1's					
Unrecovered Purchased Gas Cost	13,427,981		13,427,981		13,427,981
Amortization of Loss on Bond Retirements	(321,439)	(724,447)	(1,045,886)		(1,045,886)
FAS 106 - Deferred Expense	(54,531)		(54,531)		(54,531)
Gas IRP	(88,708)		(88,708)		(88,708)
Rate Case Expense	47,577	593,581	641,158		641,158
Permanent M-1's					
Meals & Entertainment	(86,095)	(129,394)	(215,489)	(12,706)	(228,195)
Preferred Stock Expense Amortization	(9,611)	(21,660)	(31,271)		(31,271)
Lobbying Expense				(108,000)	(108,000)
KESOP				3,462,839	3,462,839
Restricted Stock Bonus				235,555	235,555
SISP				370,270	370,270
Federal Nonhwy Use Tax Credit	(8,169)	(12,277)	(20,446)		(20,446)
Total M-1 Deductions	$12,715,396	$1,709,317	$14,424,713	$2,538,538	$16,963,251

DOCKET NO. _____
RULE 20:10:13:88
STATEMENT K
PAGE 3 OF 16

MONTANA DAKOTA UTILITIES CO.
COMPUTATION OF INCOME TAX LIABILITY AND TAX SAVINGS
BASED ON MDU RESOURCES GROUP, INC. 2002
CONSOLIDATED FEDERAL INCOME TAX RETURN

	Montana-Dakota Utilities Co.	MDU Resources Group, Inc. 1/
Net Taxable Income (Loss)	$8,081,938	$117,795,237
Federal Income Tax:		
Statutory Taxes @ 35%	$2,828,585	$41,228,333
Less Credits:		
Nonconventional Source Fuel Credit		246,678
General Business Credit	6,353	269,520
Total Tax	$2,822,232	$40,712,135
Tax Savings Arising From Consolidation	$0	

Montana Dakota Utilities Co. is a member of a group that files a consolidated Federal Income Tax Return. There are no tax savings available to Montana-Dakota Utilities Co. as a result of being included in a consolidated tax return during the test period.

1/ Reflects MDU Resources Group, Inc. and includible subsidiaries.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company	South Dakota
Operating Revenue	$237,207,834	$44,781,441
Operating Expense:		
O&M Expense	217,820,526	41,600,756
Depreciation Expense	8,477,139	1,815,584
Taxes Other than Income	4,647,527	736,251
Total Operating Expense	230,945,192	44,152,591
Operating Income	6,262,642	628,850
Interest Expense	3,265,632	811,985
Book Taxable Income before Adjustments	2,997,010	(183,135)
Deductions and Adjustments to Book Income:		
Tax Deductions 1/	12,715,396	2,863,648
Preferred Dividend Paid Deduction	52,184	12,470
Total Deductions and Adjustments	12,767,580	2,876,118
Taxable Income - Before State Income Tax	(9,770,570)	(3,059,253)
Less: State Income Taxes	(582,346)	
Federal Taxable Income	(9,188,224)	(3,059,253)
Federal Income Taxes @ 35%	(3,215,879)	(1,070,739)
Credits and Adjustments	(7,532)	(1,537)
State Income Taxes	(582,346)	
Federal and State Income Taxes	(3,805,757)	(1,072,276)
Rounding and Prior Year's Adjustment	(318,854)	(46,139)
Total Federal and State Income Taxes	($4,124,611)	($1,118,415)

1/ See page 6.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
TAX DEDUCTIONS
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company	South Dakota
1900 Account M-1's		
Management Incentive Compensation	($191,611)	($39,095)
Pension Expense	657,311	134,114
Sundry Reserves	914	218
Property Insurance Adjustment	214,996	46,060
Bad Debt Expense	(82,083)	(14,807)
Accrued Vacation	(201,310)	(41,074)
Capitalized Overheads	(104,056)	(21,231)
Customer Advances	148,585	18,590
Restricted Stock Bonus Plan	(241,823)	(49,340)
FAS 106 - OPRB	4,836	987
Deferred Compensation	(226,864)	(46,288)
BOD Retirement	14,173	2,892
Demand Charges	345,925	82,536
PCB Related Income	11,720	2,681
2820 Account M-1's		
Liberalized Depreciation and Other Property Timing Differences	(394,426)	(88,507)
Contributions in Aid of Construction	(147,896)	(9,923)
2830 Account M-1's		
Purchased Gas Cost Adjustment	13,427,981	2,915,264
Amortization of Loss on Bond Retirements	(321,439)	(76,812)
FAS 106 - Deferred Expense	(54,531)	(15,863)
Gas IRP	(88,708)	
Rate Case Expense	47,577	84,776
Permanent M-1's		
Meals & Entertainment	(86,095)	(17,566)
Preferred Stock Expense Amortization	(9,611)	(2,297)
Federal Nonhwy Use Tax Credit	(8,169)	(1,667)
Total M-1 Deductions	$12,715,396	$2,863,648

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
INTEREST EXPENSE ANNUALIZATION
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003
PRO FORMA ADJUSTMENT NO. 26

	Per Books	Pro Forma Adjustments	Pro Forma
Rate Base 1/	$17,941,833	$1,178,113	$19,119,946
Long Term Debt Ratio 2/			45.589%
Long Term Debt Cost 2/			8.624%
Weighted Cost of Debt 2/			3.932%
Interest Expense - Pro Forma			$751,796
Interest Expense - Per books 3/			811,985
Pro Forma Adjustment			($60,189)

1/ Rule 20:10:13:96, page 4.
2/ Rule 20:10:13:72, Statement G, page 2.

MONTANA-DAKOTA UTILITIES CO.
DEFERRED INCOME TAX ON PLANT ADDITIONS
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 27 AND
ADJUSTMENT F

Tax Depreciation on Plant Additions	$267,657
Book Depreciation on Plant Additions 1/	95,843
Tax Depreciation on Plant Additions	$171,814
Deferred Income Taxes on Plant Additions - Current	$60,135

1/ Includes depreciation on accounts charged to clearing accounts.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF ADJUSTMENT TO
CURRENT INCOME TAXES
GAS UTILITY - SOUTH DAKOTA
ADJUSTMENT NO. 28

	Pro Forma Adjustments
Operating Revenues	
Sales Revenues	$13,538,238
Transportation Revenues	(38,401)
Other Revenues	47,709
Total Operating Revenues	13,547,546
Operating Expenses	
Operation and Maintenance	
Cost of Gas	11,747,188
Other O&M	1,252,379
Total O&M	12,999,567
Depreciation Expense	26,763
Taxes other Than Income	91,585
Total Operating Expenses	13,117,915
Gross Adjustments to Operating Income	429,631
Deductions and Adjustments to Book Income:	
Interest Annualization 1/	(60,189)
Tax Depreciation on Plant Additions 2/	171,814
Total Adjustments to Taxable Income	111,625
Taxable Income	318,006
Federal & State Income Taxes @ 35%	$111,302

1/ Rule 20:10:13:88, Statement K, page 7.
2/ Rule 20:10:13:88, Statement K, page 14.

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO CURRENT AND DEFERRED INCOME TAXES
FOR ROUNDING AND PRIOR YEAR'S AND CLOSING/FILING
GAS UTILITY - SOUTH DAKOTA
ADJUSTMENT NO. 29

Adjustment to Current Federal Income Taxes to Eliminate Closing/Filing and Prior Years Adjustments	$46,139
Adjustment to Deferred Income Taxes to Eliminate Closing/Filing	($44,463)

MONTANA DAKOTA UTILITIES CO.
ACCUMULATED DEFERRED INCOME TAXES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

BALANCE AT:	Total Company	Electric	Gas	Other	Non-Utility
ACCOUNT 190:					
January 31, 2003	(21,700,920)	(569,121)	(2,005,751)	(10,994,135)	(8,131,913)
February 28, 2003	(22,656,644)	(546,970)	(2,892,490)	(11,039,708)	(8,177,476)
March 31, 2003	(23,159,044)	(524,815)	(3,418,738)	(11,038,301)	(8,177,190)
April 30, 2003	(22,938,736)	(502,656)	(3,191,238)	(11,022,089)	(8,222,753)
May 31, 2003	(22,152,437)	(465,169)	(2,520,789)	(10,898,163)	(8,268,316)
June 30, 2003	(20,995,794)	(443,002)	(1,358,268)	(10,866,804)	(8,327,720)
July 31, 2003	(19,942,389)	(428,116)	(291,704)	(10,835,445)	(8,387,124)
August 31, 2003	(18,754,654)	(413,224)	764,753	(10,661,423)	(8,444,760)
September 30, 2003	(17,913,780)	(398,327)	1,605,393	(10,618,450)	(8,502,396)
October 31, 2003	(17,641,831)	(383,426)	1,871,163	(10,570,933)	(8,558,635)
November 30, 2003	(18,256,319)	(368,521)	1,242,782	(10,515,706)	(8,614,874)
December 31, 2003	(21,238,378)	(549,841)	(334,935)	(11,639,190)	(8,714,412)
ACCOUNT 282: (Other Property)					
January 31, 2003	67,758,020	53,738,071	14,389,482	(436,843)	67,310
February 28, 2003	67,578,281	53,649,455	14,371,578	(510,062)	67,310
March 31, 2003	67,398,542	53,560,839	14,353,674	(583,281)	67,310
April 30, 2003	68,656,715	54,181,151	14,479,002	(70,748)	67,310
May 31, 2003	68,836,454	54,269,767	14,496,906	2,471	67,310
June 30, 2003	69,016,193	54,358,383	14,514,810	75,690	67,310
July 31, 2003	69,195,932	54,446,999	14,532,714	148,909	67,310
August 31, 2003	69,600,340	54,535,615	14,550,618	446,797	67,310
September 30, 2003	69,798,398	54,624,231	14,568,522	538,335	67,310
October 31, 2003	70,003,623	54,712,847	14,586,426	637,040	67,310
November 30, 2003	70,221,010	54,801,463	14,604,330	747,907	67,310
December 31, 2003	68,422,596	55,558,925	13,995,852	(1,242,781)	110,600
ACCOUNT 283: (Other)					
January 31, 2003	5,342,211	486,812	2,765,136	1,299,056	791,207
February 28, 2003	5,421,266	486,812	2,879,907	1,263,340	791,207
March 31, 2003	5,890,000	486,812	3,384,357	1,227,624	791,207
April 30, 2003	5,038,693	486,812	2,568,766	1,191,908	791,207
May 31, 2003	5,389,161	486,812	2,954,950	1,156,192	791,207
June 30, 2003	6,808,449	486,812	4,409,954	1,120,476	791,207
July 31, 2003	8,258,550	486,812	5,895,771	1,084,760	791,207
August 31, 2003	8,469,121	486,812	6,142,058	1,049,044	791,207
September 30, 2003	8,538,016	486,812	6,246,669	1,013,328	791,207
October 31, 2003	8,814,512	486,812	6,558,881	977,612	791,207
November 30, 2003	8,332,725	486,812	6,112,810	941,896	791,207
December 31, 2003	9,494,976	721,556	6,985,720	1,018,484	769,216
TOTAL COMPANY					
January 31, 2003	51,399,311	53,655,762	15,148,867	(10,131,922)	(7,273,396)
February 28, 2003	50,342,903	53,589,297	14,358,995	(10,286,430)	(7,318,959)
March 31, 2003	50,129,498	53,522,836	14,319,293	(10,393,958)	(7,318,673)
April 30, 2003	50,756,672	54,165,307	13,856,530	(9,900,929)	(7,364,236)
May 31, 2003	52,073,178	54,291,410	14,931,067	(9,739,500)	(7,409,799)
June 30, 2003	54,828,848	54,402,193	17,566,496	(9,670,638)	(7,469,203)
July 31, 2003	57,512,093	54,505,695	20,136,781	(9,601,776)	(7,528,607)
August 31, 2003	59,314,807	54,609,203	21,457,429	(9,165,582)	(7,586,243)
September 30, 2003	60,422,634	54,712,716	22,420,584	(9,066,787)	(7,643,879)
October 31, 2003	61,176,304	54,816,233	23,016,470	(8,956,281)	(7,700,118)
November 30, 2003	60,297,416	54,919,754	21,959,922	(8,825,903)	(7,756,357)
December 31, 2003	56,679,194	55,730,640	20,646,637	(11,863,487)	(7,834,596)

MONTANA-DAKOTA UTILITIES CO.
DEFERRED INCOME TAXES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Utility	South Dakota
Gas Utility - Rate Base Deductions:		
Depreciation, Retirements and Other Timing Differences Required to be Normalized	($399,165)	($88,008)
Contributions In Aid of Construction	(56,870)	(3,473)
Montana Net Negative Salvage	40,768	
Customer Advances	57,569	6,507
Acquisition Adjustments	(11,577)	
Total Rate Base Deductions	(369,275)	(84,974)
Gas Utility - Current Timing Differences:		
Management Incentive Compensation	(73,055)	(13,683)
Pension Expense	250,609	46,940
Sundry Reserves	344	76
Property Insurance Adjustment	81,544	16,121
Bad Debt Expense	(31,301)	(5,182)
Accrued Vacation	(76,752)	(14,376)
Capitalized Overheads	(39,673)	(7,431)
Restricted Stock Bonus Plan	(92,199)	(17,269)
FAS 106	(18,943)	(5,207)
Deferred Compensation	(86,494)	(16,201)
BOD Retirement	5,404	1,012
Demand Charges	131,774	28,888
PCB Related Income	4,469	939
Unrecovered Purchased Gas Cost	5,097,135	1,020,342
Amort of Loss on Bond Retirements	(121,000)	(26,884)
Gas IRP	(35,062)	
Rate Case Expense	14,749	29,672
Closing/Filing and Out of Period	328,924	44,463
Total Current Timing Differences	5,340,473	1,082,220
Total Deferred Income Taxes	$4,971,198	$997,246

MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF ACCUMULATED DEFERRED INCOME TAXES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company		South Dakota		
	Balance 12/31/02	Balance 12/31/03	Balance 12/31/02	Balance 12/31/03	Average Balance
Gas Utility - Rate Base Deductions:					
Depreciation, Retirements and Other Timing Differences Required to be Normalized	$7,908,929	$8,145,534	$1,880,047	$2,105,426	$1,992,737
Contributions In Aid of Construction	(241,476)	(300,282)	(56,667)	(60,140)	(58,404)
North Dakota Full Normalization	339,490	122,555	(57,030)	(114,060)	(85,545)
Customer Advances for Construction	(275,701)	(218,132)	(31,636)	(25,129)	(28,383)
Other	369,676	410,444			0
Acquisition Adjustment		(11,577)			
Total	$8,100,918	$8,148,542	$1,734,714	$1,906,097	$1,820,405
Gas Utility - Current Timing Differences:					
Management Incentive Compensation	($112,892)	($185,947)			
Pension Expense	1,310,834	1,561,443			
Uncollectable Accounts	(22,005)	(53,306)			
Unbilled Revenues	172,888	172,888			
Workers Comp	14,146	14,146			
Capitalized Overheads	(734,754)	(712,827)			
Restricted Stock Bonus Plan	(247,780)	(342,321)			
Contingency Reserve	(1,873,942)	(1,907,371)			
Delivered/Unbilled Revenue	623,187	623,187			
BOD Retirement	(248,081)	(242,677)			
Rate 71 Refund	14,738	14,738			
FAS 106	366,423	345,636			
Demand Charges	1,349,511	1,481,285			
PCB Related Income	81,874	86,343			
Rate Case Expense	128,603	143,352			
Unrecovered Purchased Gas Cost	601,829	5,698,964			
Environmental Tax	4,386	4,386			
Gas IRP	63,464	28,402			
Total	$1,492,429	$6,730,321			
Total Gas Utility	$9,593,347	$14,878,863			

DOCKET NO. _____
RULE 20:10:13:88
STATEMENT K
PAGE 13 OF 16

MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF UNAMORTIZED INVESTMENT TAX CREDITS
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company	South Dakota
Balance @		
December 31, 2002	$518,742	$26,861
December 31, 2003	413,147	13,297
Average Balance	$465,945	$20,079

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO ACCUMULATED DEFERRED INCOME TAXES
TO REFLECT FULL NORMALIZATION
GAS UTILITY - SOUTH DAKOTA
ADJUSTMENT G

Amortization of deferred taxes to reflect full normalization	($57,030)

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED DEFERRED INCOME TAXES
ACCUMULATED INVESTMENT TAX CREDITS
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT F AND ADJUSTMENT H

	Balance @ 12/31/02	Balance @ 12/31/03	Average Balance @ 12/31/03	Adjustments	Pro Forma Balance @ 12/31/04	Average Balance	Pro Forma Adjustment
Accumulated Deferred Income Taxes							
Liberalized Depreciation	$1,766,350	$1,931,226	$1,848,788	$3,105 1/	$1,934,331	$1,932,779	$83,991
Customer Advances	(31,636)	(25,129)	(28,383)		(25,129)	(25,129)	3,254
Balance	$1,734,714	$1,906,097	$1,820,405	$3,105	$1,909,202	$1,907,650	$87,245
Accumulated Investment Tax Credits							
Balance	$26,861	$13,297	$20,079	$13,297	$0	$6,649	($13,430)

1/ Includes deferred taxes on plant additions and full normalization.

DOCKET NO. ____
RULE 20:10:13:88
STATEMENT K
PAGE 16 OF 16

MDU RESOURCES GROUP, INC.
RECONCILIATION OF NET INCOME PER BOOKS WITH TAXABLE INCOME PER FEDERAL INCOME TAX RETURN
FOR TAX YEARS 1999-2002

M-1 Line No.		2002	2001	2000	1999
1	**Net Income per Books**	$148,443,959	$155,848,506	$111,028,299	$84,079,784
2	**Federal Income Tax**	6,299,950	10,359,280	11,415,372	8,602,112
3	**Excess of Capital Losses Over Capital Gains**	264	0	0	0
4	**Income Subject to Tax not Recorded on Books This Year:**				
	Other				
	Dividends Received from Subsidiary Companies	51,045,000	39,709,000	34,649,500	28,591,800
	G/L on Intercompany Trans. Under Reg Sec 1.1502-13	205,128			
	Jt Venture & Partnership Ordinary Income	77,132	99,639	100,999	71,696
	Contributions in Aid of Construction	720,397	268,101	287,951	(78,979)
	Customer Advances		330,767	(31,713)	230,817
	Federal Non-highway Use Tax Credit	18,904	18,761	19,658	17,723
	Gain on Retirement of Assets - Tax	75,023	887,626	(371,684)	(185,636)
	Total	52,141,584	41,313,894	34,654,711	28,647,421
5	**Expenses Recorded on Books This Year not Deducted on This Return:**				
	Depreciation	26,720,353	26,361,318	25,400,418	24,324,027
	Meals & Entertainment	220,435	226,971	210,693	167,207
	Other				
	Increase in Capitalized Overheads		805,471	34,186	124,248
	Increase in Capitalized Overheads - Stores	65,859	64,697	65,030	58,298
	Demand Charges	383,847	8,194	251,462	109,107
	Unrecovered Purchased Gas Costs		21,010,649	4,116,950	2,304,705
	Bad Debt Expense per Books	573,825	1,593,836	1,081,029	734,276
	Increase in Capitalized Overheads - Non-operating	19,108	62,678	52,469	28,968
	Supplemental Income Security Plan	1,796,484	83,247	1,542,306	2,444,095
	Capitalized Property Taxes	266,147	70,406	117,138	111,560
	State Income Tax Accrual per Books	1,875,420	1,217,822	2,177,260	1,520,817
	Post Retirement Benefits Accrued	1,142	1,923,299		429,419
	Increase in Sundry Reserves			54,439	
	Capitalized Interest Expense	353,768	337,186	169,399	231,213
	Amortizaiton per Books	2,767,104	2,473,984	2,121,959	1,408,993
	Accrued Vacation Pay	82,072		381,575	525,397
	Amortization of Loss on Bond Retirements	1,201,783	1,295,507	1,388,692	1,481,731
	Book Depreciation Charged to Expense	1,148,792	1,082,985	1,008,364	952,351
	Capitalized Tax Depreciation	715,179	623,116	571,179	514,448
	Lobbying Expense	70,864	114,117	72,226	97,881
	Deferred Compensation for Directors	97,778	125,828	200,915	26,701
	Deferred Compensation - Net Deferral	296,667	463,790		
	Penalties		6,086	120	465
	Property Insurance Adjustment	112,551	107,240	271,011	267,652
	Reusable Property to Expense	3,402	2,584	2,586	694
	Integrated Resource Plan	88,708	88,708	88,708	100,961
	Workers Compensation				6,880
	Restricted Stock Bonus Plan	571,998	827,981	502,014	408,146
	Provision for Gas Refunds	67,067			
	Reserve for Natural Gas Minimum Bill Obligation	5,342,863			
	Reserve for Corporation Loan	176,000			
	Total Other	18,078,428	34,389,411	16,271,017	13,889,006
6	**Total of Lines 1 Through 5**	$251,904,973	$268,499,380	$198,980,510	$159,709,557

MDU RESOURCES GROUP, INC.
RECONCILIATION OF NET INCOME PER BOOKS WITH TAXABLE INCOME PER FEDERAL INCOME TAX RETURN
FOR TAX YEARS 1999-2002

M-1 Line No.		2002	2001	2000	1999
7	**Income Recorded on Books This Year not Included on This Return:**				
	Other				
	Book Gain on Disposition of Property	348,912	2,311	2,164	(9,79
	G/L on Interco. Trans. under reg sec 1.1502-13		884,358		
	Joint venture & partnership operating income	20,456	20,000		
	Equity in Earnings of Subsidiary Companies	128,320,376	135,692,353	87,788,729	64,143,72
	Allowance for Funds Used During Construction	101,231	185,066	157,410	419,93
		128,790,975	136,784,088	87,948,303	64,553,86
8	**Deductions on This Return not Charged Against Book Income This Year:**				
	Depreciation	29,160,076	22,657,193	23,839,600	22,863,06
	Contributions Carryover		4,537,084	6,639,606	
	Other				
	Pension Expense per Return	3,421,343	3,965,568	3,849,479	1,755,78
	Post Retirement Benefits	797,522	1,894,963	510,702	
	Bad Debt Expense per Return	666,420	1,814,870	764,866	687,46
	Decrease in Sundry Reserves	31,614	67,119		2,91
	Deferred Compensation			246,937	599,78
	Unrecovered Purchased Gas Cost	25,954,577			
	Environmental Costs	14,754	19,586	569,234	190,15
	KESOP Incentive Compensation	361,912	4,379,752	1,439,653	266,17
	State Income Tax Accrual per Return	413,325	3,062,638	1,729,801	2,198,15
	Reserve for deferred maintenance		46,599		
	Vacation accrual		324,210		
	Workers compensation		181,167		
	1991 Interest Expense			10,124	
	Expenses for the Retirement of Assets	410,093	344,330	355,479	386,13
	Restricted Stock Bonus Plan - Dividends	807,134	468,699	134,133	145,24
	Decrease in Capitalized Overheads	622,788			
	Customer Advances	169,810			
	Unamortized Regulatory Commission Expense	544,543			
	Charitable Deduction	150			
	Acquisition Costs	430,997			
		34,646,982	16,569,501	9,610,408	6,231,80
9	**Add Lines 7 and 8**	192,598,033	180,547,866	128,037,917	93,648,73
10	**Income (Form 1120, Page 1, Line 28) - Line 6 less Line**	59,306,940	87,951,514	70,942,593	66,060,82
	Less: Special Deductions	51,225,002	39,889,003	35,027,503	29,167,80
	Taxable Income (Form 1120, Page 1, Line 30)	$8,081,938	$48,062,511	$35,915,090	$36,893,01

MONTANA-DAKOTA UTILITIES CO.
DIFFERENCE IN BOOK AND TAX DEPRECIATION - GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Tax Depreciation	
CIAC's - MACRS	($205,248)
Depreciation	9,466,710
Capitalized Interest Expense	(52,789)
Capitalizd Tax Depreciation	(500,960)
Capitalized Inventory on Stores Inventory	(12,141)
Capitalized Property Taxes	(152,654)
Expenses for the Retirement of Assets	196,002
Retirement of Assets	(197,018)
Total Gas	$8,541,902
Book Depreciation	
Depreciation Expense	$8,571,668
Amortization Expense	587,831
Allowance For Funds Used During Construction	(19,706)
Total Book Depreciation	$9,139,793
Book over Tax Depreciation	$597,891

MONTANA - DAKOTA UTILITIES CO.
NET TAXABLE INCOME (LOSS) FOR EACH COMPANY INCLUDED IN MDU RESOURCES GROUP, INC.'S 2002 CONSOLIDATED FEDERAL INCOME TAX RETURN

Company	Taxable Income(Loss)	Excess Tax Depreciation	Taxable Income (Loss) after Elimination	System Tax Liability
Montana - Dakota Utilities Co.	$8,081,674	($2,191,352)	$5,890,322	$2,822,232
Centennial Energy Holdings, Inc.	0	0	0	0
Centennial Holdings Capital Corp.	(251,308)	0	(251,308)	(87,958)
Centenntial Power Inc.	98,053	233,123	331,176	34,319
RMP Montana Acquisition, Inc.	(2,464,145)	0	(2,464,145)	(951,828)
Futuresource Capital Corp.	(1,417,068)	2,636,295	1,219,227	(495,974)
Intersource Insurance Company	1,113,370	0	1,113,370	389,680
MDU Resources International, Inc.	993,511	0	993,511	347,729
Utility Services, Inc.	(2,060,776)	18,139	(2,042,637)	(721,272)
International Line Builders, Inc.	3,328,581	(90,326)	3,238,255	1,165,003
ILB Hawaii, Inc.	(2,739)	0	(2,739)	(959)
Loy Clark Pipeline Co.	(954,937)	(132,883)	(1,087,820)	(334,228)
Loy Clark Pipeline of Washington, Inc.	0	0	0	0
High Line Equipment, Inc.	0	0	0	0
Rocky Mountain Contractors, Inc.	2,932,679	136,514	3,069,193	1,026,438
Williams Construction Company, Inc.	0	0	0	0
Hamlin Electric Company	(50,571)	487,403	436,832	(17,700)
Harp Engineering, Inc	(1,878,265)	(50,281)	(1,928,546)	(657,393)
Pouk & Steinle, Inc.	4,550,969	38,867	4,589,836	1,592,839
FJ Johnson	587,144	26,236	613,380	205,500
The Wagner-Smith Company	540,110	318,567	858,677	189,039
Wagner-Smith Equipment Co.	2,029,877	1,956,236	3,986,113	710,457
Wagner-Smith Pumps & Systems, Inc.	(350,080)	(132)	(350,212)	(122,528)
Frebco, Inc.	(647,963)	11,388	(636,575)	(226,787)
Newco, Inc.	189,520	11,096	200,616	66,332
E.S.I. Inc.	(100,721)	(1,793)	(102,514)	(35,252)
Bell Communications, Inc.	0	0	0	0
Bell Electric Contractors, Inc.	2,320,134	273,234	2,593,368	812,047
Capital Electric Construction Company	(368,578)	165,232	(203,346)	(129,002)
Capital Electric Line Builders	5,418,733	83,221	5,501,954	1,896,557
Oregon Electric Construction, Inc.	(3,661,560)	245,641	(3,415,919)	(1,281,546)
WBI Holdings, Inc.	0	0	0	0
Fidelity E & P Company	(11,729,885)	259,439	(11,470,446)	(4,339,669)
Seven Brothers Ranches, Inc.	(421,952)	67,184	(354,768)	(147,683)
Fidelity Oil Company	42,394,003	(3,754,729)	38,639,274	14,655,966
Fidelity Oil Holdings, Inc.	0	0	0	0
WBI Production, Inc.	0	0	0	0
WBI Pipeline & Storage Group, Inc.	(29,828)	0	(29,828)	(10,440)
Williston Basin Interstate Pipeline Co.	26,440,280	73,908	26,514,188	9,251,218
WBI Southern, Inc.	0	0	0	0
WBI Offshore Pipeline, Inc.	0	0	0	0
Kentucky Pipeline & Storage Company, Inc.	0	0	0	0
Bitter Creek Pipeline, LLC	(12,376,779)	16,835,269	4,458,490	(4,331,873)
WBI Energy Services, Inc.	0	0	0	0
Prairielands Energy Marketing, Inc.	93,411	(109,728)	(16,317)	32,694
SAGE Gas Alliance, LLC	0	0	0	0

MONTANA - DAKOTA UTILITIES CO.
NET TAXABLE INCOME (LOSS) FOR EACH COMPANY INCLUDED IN MDU RESOURCES GROUP, INC.'S 2002 CONSOLIDATED FEDERAL INCOME TAX RETURN

Company	Taxable Income(Loss)	Excess Tax Depreciation	Taxable Income (Loss) after Elimination	System Tax Liability
Innovatum, Inc.	(1,277,809)	81,049	(1,196,760)	(448,677)
Innovative Gas Services Inc.	2,909,498	0	2,909,498	1,018,324
Marcon Energy Corp.	171,936	0	171,936	60,178
Knife River Corporation	(2,828,891)	3,051,977	223,086	(990,112)
KRC Holdings, Inc.	(33,664,041)	2,499	(33,661,542)	(11,782,414)
KRC Aggregates, Inc.	720,042	138,351	858,393	252,015
Concrete, Inc.	3,276,226	347,036	3,623,262	1,146,679
DSS Company	8,426,974	2,342,422	10,769,396	2,949,441
LTM, Incorporated	5,717,408	2,241,839	7,959,247	2,001,093
Rogue Aggregates, Inc.	985,468	529,628	1,515,096	344,914
Medford Ready Mix, Inc.	494,064	42,734	536,798	172,922
Southern Oregon Underground, Inc.	0	0	0	0
Alaska Basic Industries, Inc.	0	0	0	0
Anchorage Sand & Gravel Company, Inc.	6,306,766	(149,800)	6,156,966	2,207,368
Baldwin Contracting Company, Inc.	4,103,392	451,416	4,554,808	1,436,187
Knife River Dakota, Inc.	6,484,984	0	6,484,984	2,269,744
Knife River Hawaii, Inc.	6,532,875	0	6,532,875	2,286,506
Knife River Marine, Inc.	201,190	20,091	221,281	70,417
Morse Brothers, Inc.	7,871,385	4,012,525	11,883,910	2,754,985
Hap Taylor & Sons, Inc.	6,225,906	994,220	7,220,126	2,179,067
JTL Group, Inc. - Montana	2,925,439	4,273,771	7,199,210	1,023,904
JTL Group, Inc. - Wyoming	356,369	(321,198)	35,171	124,729
Polson Ready Mix Concrete, Inc.	0	0	0	0
Connolly-Pacific Co.	6,715,105	(396,768)	6,318,337	2,350,287
Bauerly Brothers, Inc.	9,464,717	1,003,753	10,468,470	3,312,651
WHC, Ltd.	3,462,462	360,468	3,822,930	1,211,862
Buffalo Bituminous, Inc.	1,907,148	169,541	2,076,689	667,502
Granite City Concrete of Watkins, Inc	3,048,989	73,277	3,122,266	1,067,146
Granite City Ready Mix, Inc.	1,063,797	3,993	1,067,790	372,329
Northstar Materials, Inc.	3,848,944	644,075	4,493,019	1,347,130
MDU Resources Group, Inc. and Includible Subsidiaries	$117,795,237	$37,462,667	$155,257,904	$40,712,135

MONTANA-DAKOTA UTILITIES CO.
ALLOWANCE FOR CURRENT TAX IN EXCESS OF TAX CALCULATED AT CONSOLIDATED TAX RATE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003

This schedule is not applicable since the current tax in the cost of service is not greater than the calculated income tax.

MONTANA-DAKOTA UTILITIES CO.
ALLOWANCE FOR CURRENT TAX IN EXCESS OF TAX CALCULATED AT CONSOLIDATED TAX RATE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003

This schedule is not applicable since the current tax in the cost of service is not greater than the calculated income tax.

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003

Type of Tax	Total Company	South Dakota	Pro Forma Adjustments	Pro Forma South Dakota
Ad Valorem				
Distribution	$2,252,511	$297,146	$21,201	$318,347
General	210,641	68,269	1,168	69,437
Common	198,255	22,618	3,419	26,037
Intangible	3,880	873	136	1,009
Total Ad Valorem Taxes	$2,665,287	$388,906	$25,924	$414,830
O&M Related Taxes - Other				
FICA	1,433,129	272,985	25,346	298,331
Federal & State Employment	76,009	14,478		$14,478
Franchise	96,310	0	0	0
Delaware Franchise	62,155	12,682	0	12,682
Total O&M Related Taxes	1,667,603	300,145	25,346	$325,491
Revenue Taxes				
Montana PSC	163,885			0
Montana Consumer Counsel	66,214			0
South Dakota	52,573	46,953	40,315	87,268
Wyoming	30,731			0
	313,403	46,953	40,315	87,268
Other				
Highway Use Tax	560	111		111
Secretary of State	674	137		137
	1,234	248	0	248
Total Taxes Other Than Income	$4,647,527	$736,252	$91,585	$827,837

MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING DECEMBER 31, 2003
ADJUSTMENT NO. 23

Function	Effective Tax Rate	Pro Forma Plant Balance	Pro Forma Ad Valorem Tax	Per Books Ad Valorem Tax	Pro Forma Adjustment
Distribution	0.9328%	$34,128,096	$318,347	$297,146	$21,201
General	0.7354%	9,442,056	69,437	68,269	1,168
General Intangible	0.0675%	138,705	94	0	94
Common	1.7117%	1,521,143	26,037	22,618	3,419
Common Intangible	0.0675%	1,355,918	915	873 1/	42
Total Ad Valorem Taxes		$46,585,918	$414,830	$388,906	$25,924

1/ Common and General Intangible.

MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Function	Average Plant Balance @ 12/31/03	Ad Valorem Tax @ 12/31/03	Effective Tax Rate
Distribution	$31,856,672	$297,146	0.9328%
General	9,283,492	68,269	0.7354%
Common	1,321,341	22,618	1.7117%
Intangible 1/	1,293,971	873	0.0675%
Total	$43,755,476	$388,906	

1/ General and common intangible.

MONTANA-DAKOTA UTILITIES CO.
PAYROLL TAXES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003
ADJUSTMENT NO. 24

	Per Books			Pro Forma
	Gas Utility	South Dakota	Pro Forma 1/	Adjustment
FICA	$1,433,129	$272,985		
Federal & State Unemployment	76,009	14,478		
Total	$1,509,138	$287,463	$312,809	$25,346

1/ Calculated using 2003 ratio of payroll taxes to labor and pro forma labor expense.

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO SOUTH DAKOTA GROSS RECEIPTS TAX
GAS UTILITY - SOUTH DAKOTA
ADJUSTMENT NO. 25

Pro Forma Revenue	
Sales Revenue 1/	$57,739,873
Transportation Revenue 1/	324,784
Miscellaneous Service Revenues	24,962
Rent from Gas Property	7,660
Other Gas Revenues	33,695
Late Payment Revenues 1/	47,709
Total Pro Forma Revenue	$58,178,683
Gross Receipts Tax @ .15% 2/	$87,268
Per Books Gross Receipts Tax	46,953
Pro Forma Adjustment	$40,315

1/ Rule 20:10:13:85, Statement I, page 1.
2/ Tax rate effective December 31, 2003.

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company	South Dakota	Other	Reference
Operating Revenues				
Sales	$233,447,443	$44,201,634	$189,245,809	Statement I
Transportation	2,756,722	363,186	2,393,536	Statement I
Other	1,003,669	216,621	787,048	Statement I
Total Revenues	237,207,834	44,781,441	192,426,393	
Operating Expenses				
Operation and Maintenance				
Cost of Gas	181,536,759	34,335,947	147,200,812	Statement H
Other O&M	36,283,767	7,264,809	29,018,958	Statement H
Total O&M	217,820,526	41,600,756	176,219,770	
Depreciation	8,477,139	1,815,584	6,661,555	Statement J
Taxes Other Than Income	4,647,527	736,251	3,911,276	Statement L
Current Income Taxes	(4,124,611)	(1,118,415)	(3,006,196)	Statement K
Deferred Income Taxes	4,971,198	997,246	3,973,952	Statement K
Total Expenses	231,791,779	44,031,422	187,760,357	
Operating Income	$5,416,055	$750,019	$4,666,036	
Rate Base	$76,626,660	$17,941,833	$58,684,827	
Rate of Return	7.068%	4.180%	7.951%	

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003

	Total Company	South Dakota	Other	Reference
Gas Plant in Service	$203,944,506	$43,755,476	$160,189,030	Statement D
Accumulated Reserve for Depreciation	125,315,421	24,675,602	100,639,819	Statement E
Net Gas Plant in Service	78,629,085	19,079,874	59,549,211	
CWIP in Service Pending Reclassification	1,194,868	324,862	870,006	Statement D
Total Gas Plant in Service	79,823,953	19,404,736	60,419,217	
Additions				
Materials and Supplies	1,118,645	270,692	847,953	Statement F
Fuel Stocks	24,621	0	24,621	
Gas in Underground Storage	5,652,942	0	5,652,942	
Prepayments	1,182,901	28,708	1,154,193	Statement F
Other	267,037	150,699	116,338	Statement F
Total Additions	8,246,146	450,099	7,796,047	
Total Before Deductions	$88,070,099	$19,854,835	$68,215,264	
Deductions				
Accumulated Deferred Income Taxes	10,316,015	1,820,405	8,495,610	Statement K
Accumulated Investment Tax Credits	465,945	20,079	445,866	Statement K
Customer Advances	661,479	72,518	588,961	Statement F
Total Deductions	11,443,439	1,913,002	9,530,437	
Total Rate Base	$76,626,660	$17,941,833	$58,684,827	

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PRO FORMA ADJUSTMENTS
GAS UTILITY - SOUTH DAKOTA

	Adjustment No.	Amount
REVENUE		
Sales & Transportation at Current Rates	1	$9,959,291
Weather Normalization	2	1,752,580
Annualization	3	603,717
Pro Forma 2004	4	1,184,248
Other Revenue	5	47,709
Total Adjustments to Revenue		13,547,545
OPERATION & MAINTENANCE EXPENSES		
Cost of Gas	6	11,747,188
Labor Expense	7	275,090
Benefits Expense	8	546,843
Insurance Expense	9	(44,184)
Contract Labor	10	24,685
Vehicles & Work Equipment	11	271,143
Postage Expense	12	(4,692)
Telephone Expense	13	362
Office Supplies Expense	14	(15,167)
Company Consumption	15	6,972
Uncollectible Accounts	16	69,359
Computer Rental	17	9,483
Industry Dues	18	(18,359)
Advertising Expense	19	(26,643)
Regulatory Commission Expense	20	154,437
Depreciation Study Expense	21	3,050
Total Adjustments to Other O&M		1,252,379
DEPRECIATION EXPENSE		
Average Annual Depreciation	22	26,763
TAXES OTHER THAN INCOME		
Ad Valorem Taxes	23	25,924
Payroll Taxes	24	25,346
South Dakota Gross Receipts Tax	25	40,315
Total Adjustments to Taxes Other than Income		91,585
CURRENT INCOME TAXES		
Interest Annualization	26	(60,189)
Tax Depreciation on Plant Additions	27	171,814
Income Taxes on Pro Forma Adjustments	28	111,302
Elimination of Closing/Filing and Reserve Adjustment	29	46,139
Total Adjustments to Current Income Taxes		157,441

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PRO FORMA ADJUSTMENTS
GAS UTILITY - SOUTH DAKOTA

	Adjustment No.	Amount
DEFERRED INCOME TAXES		
Elimination of Closing/Filing	29	(44,463)
Deferred Income Taxes on Plant Additions	27	60,135
Total Adjustments to Deferred Taxes		15,672
Net Adjustments to Operating Income		$256,517

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
SUMMARY OF PRO FORMA RATE BASE ADJUSTMENTS

Plant	Adjustment	Amount
Plant Additions	A	$2,505,580
Accumulated Reserve for Depreciation on Plant additions	B	1,313,495
Adjustment To Net Plant		$1,192,085
Additions:		
Materials and Supplies	C	($5,151)
Prepaid Insurance	D	63,192
Unamortized FAS 106	E	(15,864)
Total		$42,177
Deductions:		
Accumulated Def. Inc. Tax- Plant Additions & Full Normalization	F,G	$87,245
ITCs	H	(13,430)
Customer Advances for Construction	I	(17,666)
		$56,149
Total Pro Forma Adjustments		$1,178,113

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003
PRO FORMA

	Per Books	Pro Forma Adjustments	Pro Forma
Operating Revenues			
Sales	$44,201,634	$13,538,238	$57,739,872
Transportation	363,186	(38,401)	324,785
Other	216,621	47,709	264,330
Total Revenues	44,781,441	13,547,546	58,328,987
Operating Expenses			
Operation and Maintenance			
Cost of Gas	34,335,947	11,747,188	46,083,135
Other O&M	7,264,809	1,252,379	8,517,188
Total O&M	41,600,756	12,999,567	54,600,323
Depreciation	1,815,584	26,763	1,842,347
Taxes Other Than Income	736,251	91,585	827,836
Current Income Taxes	(1,118,415)	157,441	(960,974)
Deferred Income Taxes	997,246	15,672	1,012,918
Total Expenses	44,031,422	13,291,028	57,322,450
Operating Income	$750,019	$256,518	$1,006,537
Average Rate Base	$17,941,833	$1,178,113	$19,119,946
Rate of Return	4.180%		5.264%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003
PRO FORMA

	2003	Pro Forma Adjustments	Pro Forma
Gas Plant in Service	$43,755,476	$2,505,580	$46,261,056
Accumulated Reserve for Depreciation	24,675,602	1,313,495	25,989,097
Net Gas Plant in Service	19,079,874	1,192,085	20,271,959
CWIP in Service Pending Reclassification	324,862		324,862
Total Gas Plant in Service	19,404,736	1,192,085	20,596,821
Additions			
Materials and Supplies	$270,692	($5,151)	$265,541
Prepayments	28,708	63,192	91,900
Unamortized FAS 106	150,699	(15,864)	134,835
Total Additions	450,099	42,177	492,276
Total Before Deductions	$19,854,835	$1,234,262	$21,089,097
Deductions			
Accumulated Deferred Income Taxes	$1,820,405	$87,245	$1,907,650
Accumulated Investment Tax Credits	20,079	(13,430)	6,649
Customer Advances	72,518	(17,666)	54,852
Total Deductions	1,913,002	56,149	1,969,151
Total Rate Base	$17,941,833	$1,178,113	$19,119,946

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - SOUTH DAKOTA

	Before Additional Revenue Requirements	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$57,739,872	**$1,282,133**	$59,022,005
Transportation	324,785		324,785
Other	264,330		264,330
Total Revenues	58,328,987	1,282,133	59,611,120
Operating Expenses			
Operation and Maintenance			
Cost of Gas	46,083,135		46,083,135
Other O&M	8,517,188		8,517,188
Total O&M	54,600,323		54,600,323
Depreciation	1,842,347		1,842,347
Taxes Other Than Income	827,836	1,923 1/	829,759
Current Income Taxes	(960,974)	448,074 1/	(512,900)
Deferred Income Taxes	1,012,918		1,012,918
Total Expenses	57,322,450	449,997	57,772,447
Operating Income	$1,006,537	$831,463	$1,838,000
Rate Base	$19,119,946		$19,119,946
Rate of Return	**5.264%**		**9.613%**

1/ Reflects taxes at 35% after deducting South Dakota Gross Receipts of .15%.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENT
PRO FORMA 2004

Cost of Service By Component	Total South Dakota	Residential			Firm General		
		Demand	Energy	Customer	Demand	Energy	Customer
Pro Forma Rate Base	19,119,933	4,011,916	1,318	8,584,505	2,503,570	900	3,170,510
Operating Income for Proposed Return	1,837,998	385,665	127	825,228	240,668	87	304,781
Pro Forma Operating Income	1,006,532	(651,805)	2,866,741	(1,646,019)	(409,524)	1,436,853	(727,520)
Increase in Operating Income	831,466	1,037,470	(2,866,614)	2,471,247	650,192	(1,436,766)	1,032,301
Related Taxes for Increase							
Federal Income	448,748	559,930	(1,547,131)	1,333,749	350,913	(775,433)	557,140
South Dakota Gross Receipts Tax	1,925	2,400	(6,631)	5,716	1,504	(3,323)	2,388
Total Increase in Revenue	1,282,139	1,599,800	(4,420,376)	3,810,712	1,002,609	(2,215,522)	1,591,829
Pro Forma Revenues before Increase	58,328,987	4,762,572	22,886,191	3,559,780	3,249,565	14,824,380	812,218
Total Cost of Service Required From Rates	59,611,126	6,362,372	18,465,815	7,370,492	4,252,174	12,608,858	2,404,047
Less Pro Forma Cost of Gas	46,083,134	4,724,293	18,160,615	0	3,225,382	12,398,664	0
Net Distribution Costs	13,527,992	1,638,079	305,200	7,370,492	1,026,792	210,194	2,404,047
Billing Units at Customer							
Dk Throughput		3,280,458	3,280,458	0	2,239,643	2,239,643	0
Bills		0	0	455,196	0	0	61,104
Unit Cost of Service							
$ Per Dk		0.499	0.093	0.000	0.458	0.094	0.000
$ Per Customer Per Month		0.000	0.000	16.192	0.000	0.000	39.344

DOCKET NO. _____
RULE 20:10:13:97
STATEMENT N
SCHEDULE N-1
PAGE 1 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENT
PRO FORMA 2004

	Firm Contract			Air Force		
Cost of Service By Component	Demand	Energy	Customer	Demand	Energy	Customer
Pro Forma Rate Base	224,068	258	13,798	0	230	29,534
Operating Income for Proposed Return	21,540	25	1,326	0	22	2,839
Pro Forma Operating Income	(36,191)	111,142	(3,630)	(2,468)	9,059	373
Increase in Operating Income	57,731	(111,117)	4,956	2,468	(9,037)	2,466
Related Taxes for Increase						
Federal Income	31,157	(59,971)	2,675	1,332	(4,877)	1,331
South Dakota Gross Receipts Tax	134	(257)	11	6	(21)	6
Total Increase in Revenue	89,022	(171,345)	7,642	3,806	(13,935)	3,803
Pro Forma Revenues before Increase	277,574	3,607,987	1,927	244,406	3,056,397	1,372
Total Cost of Service Required From Rates	366,596	3,436,642	9,569	248,212	3,042,462	5,175
Less Pro Forma Cost of Gas	275,458	3,382,197	0	244,142	2,991,592	0
Net Distribution Costs	91,138	54,445	9,569	4,070	50,870	5,175
Billing Units at Customer						
Dk Throughput	640,689	640,689	0	573,102	573,102	0
Bills	0	0	12	0	0	12
Unit Cost of Service						
$ Per Dk	0.142	0.085	0.000	0.007	0.089	0.000
$ Per Customer Per Month	0.000	0.000	797.417	0.000	0.000	431.250

DOCKET NO. _____
RULE 20:10:13:97
STATEMENT N
SCHEDULE N-1
PAGE 2 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENT
PRO FORMA 2004

Cost of Service By Component	Small Interruptible			Large Interruptible		
	Demand	Energy	Customer	Demand	Energy	Customer
Pro Forma Rate Base	96,904	54	251,586	145,038	96	85,648
Operating Income for Proposed Return	9,315	5	24,185	13,943	9	8,233
Pro Forma Operating Income	(15,145)	111,402	(54,937)	(22,253)	63,675	(23,221)
Increase in Operating Income	24,460	(111,397)	79,122	36,196	(63,666)	31,454
Related Taxes for Increase						
Federal Income	13,201	(60,121)	42,703	19,535	(34,361)	16,976
South Dakota Gross Receipts Tax	57	(258)	183	84	(147)	73
Total Increase in Revenue	37,718	(171,776)	122,008	55,815	(98,174)	48,503
Pro Forma Revenues before Increase	37,942	320,103	51,535	38,985	574,202	21,851
Total Cost of Service Required From Rates	75,660	148,327	173,543	94,800	476,028	70,354
Less Pro Forma Cost of Gas	37,082	142,535	0	37,741	463,433	0
Net Distribution Costs	38,578	5,792	173,543	57,059	12,595	70,354
Billing Units at Customer						
Dk Throughput	406,921	406,921	0	622,478	622,478	0
Bills	0	0	444	0	0	108
Unit Cost of Service						
$ Per Dk	0.095	0.014	0.000	0.092	0.020	0.000
$ Per Customer Per Month	0.000	0.000	390.863	0.000	0.000	651.426

DOCKET NO. _____
RULE 20:10:13:97
STATEMENT N
SCHEDULE N-1
PAGE 3 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
SUMMARY REPORT
PRO FORMA 2004

Pro Forma Operating Income and Rate of Return	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Operating Revenues	58,328,987	31,208,543	18,886,163	3,887,488	3,302,175	409,580	635,038
Operating Expenses							
O&M Cost of Purchased Gas	46,083,134	22,884,908	15,624,046	3,657,655	3,235,734	179,617	501,174
Other O&M Expense	8,517,190	6,081,475	2,139,025	61,034	14,730	135,723	85,203
Total Operation & Maint. Exp.	54,600,324	28,966,383	17,763,071	3,718,689	3,250,464	315,340	586,377
Depreciation	1,842,349	1,215,495	552,520	22,816	1,346	32,791	17,381
Taxes Other Than Income Taxes	827,837	568,902	226,871	8,354	1,201	13,779	8,730
Fed. & State Inc. Taxes - Current	(960,975)	(558,437)	(323,607)	(26,152)	(50,175)	5,165	(7,769)
Deferred Income Taxes	1,012,920	447,283	367,499	92,460	92,375	1,185	12,118
Total Operating Expenses	57,322,455	30,639,626	18,586,354	3,816,167	3,295,211	368,260	616,837
Operating Income	1,006,532	568,917	299,809	71,321	6,964	41,320	18,201
Rate Base	19,119,933	12,597,739	5,674,980	238,124	29,764	348,544	230,782
Rate of Return	5.264%	4.516%	5.283%	29.951%	23.397%	11.855%	7.887%

DOCKET NO. _____
RULE 20:10:13:97
STATEMENT N
SCHEDULE N-1
PAGE 4 OF 21

MONTANA-DAKOTA UTILITIES
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PRO FORMA CHANGES IN OPERATING INCOME

Pro Forma Changes in Operating Income	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Revenue @ Current Rates							
Sales Revenue	14,812,555	7,426,696	5,073,138	1,269,749	989,398	(20,066)	73,640
Unbilled Revenue	(1,312,722)	(717,078)	(417,166)	(79,298)	(69,291)	(12,931)	(16,958)
Late Payment Penalty Revenues	47,710	26,062	15,161	2,882	2,518	470	617
Total Revenue	13,547,543	6,735,680	4,671,133	1,193,333	922,625	(32,527)	57,299
Cost of Gas	11,747,187	5,579,120	3,810,745	1,290,805	987,178	(19,511)	98,850
Labor Expense							
Other Gas Supply	4,030	2,877	1,011	29	7	65	41
Distribution	135,353	86,879	42,008	1,286	118	3,093	1,969
Customer Accounts	60,016	52,855	7,095	1	1	51	13
Customer Service & Information	2,188	1,927	259	0	0	2	0
Sales	14,551	12,815	1,720	0	0	13	3
Administrative & General	58,951	42,108	14,791	423	104	937	588
Total Labor Expense	275,089	199,461	66,884	1,739	230	4,161	2,614
Benefits Expense	546,844	390,604	137,206	3,919	958	8,698	5,459
Insurance Expense	(44,184)	(31,560)	(11,086)	(317)	(77)	(703)	(441)
Advertising Expense	(26,645)	(23,464)	(3,150)	(1)	(1)	(23)	(6)
Postage Expense	(4,692)	(4,132)	(555)	0	0	(4)	(1)
Industry Dues	(18,360)	(13,113)	(4,607)	(132)	(32)	(292)	(184)
Regulatory Commission Expense	154,439	110,313	38,749	1,107	271	2,457	1,542
All Other O&M	369,889	264,206	92,807	2,651	649	5,883	3,693
Total Other O&M	1,252,380	892,315	316,248	8,966	1,998	20,177	12,676

DOCKET NO. RULE 20:10:13:97
STATEMENT N
SCHEDULE N-1
PAGE 5 OF 21

MONTANA-DAKOTA UTILITIES
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PRO FORMA CHANGES IN OPERATING INCOME

Pro Forma Changes in Operating Income	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Depreciation Expense	26,763	17,671	7,951	348	31	465	297
Taxes Other than Income							
Ad Valorem Tax	25,924	17,117	7,702	337	30	450	288
Other Taxes - Payroll, Franchise, Other	65,660	46,901	16,474	470	115	1,044	656
Total Taxes Other than Income	91,584	64,018	24,176	807	145	1,494	944
Current Income Taxes							
Interest Annualization	(60,188)	(39,563)	(17,963)	(749)	(93)	(1,095)	(725)
Tax Depreciation on Plant Additions	171,813	113,441	51,046	2,235	197	2,986	1,908
Net Pro Forma Adjustments to Income	318,004	108,678	478,930	(109,079)	(66,831)	(37,043)	(56,651)
Taxes on Pro Forma Adjustments	111,302	38,037	167,626	(38,177)	(23,391)	(12,965)	(19,828)
Elimination of Closing/Filing & Reserve Adjustment	46,138	30,463	13,708	600	53	802	512
Total Current Income Tax Adjustments	157,440	68,500	181,334	(37,577)	(23,338)	(12,163)	(19,316)
Deferred Income Taxes							
Other	60,137	39,705	17,866	783	69	1,046	668
Closing/Filing and Out of Period	(44,463)	(29,357)	(13,210)	(578)	(51)	(773)	(494)
Total Deferred Income Tax	15,674	10,348	4,656	205	18	273	174
Total Adjustments to Income	256,515	103,708	326,023	(70,221)	(43,407)	(23,262)	(36,326)

DOCKET NO. ___
RULE 20:10:13:9
STATEMENT N
SCHEDULE N-1
PAGE 6 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PRO FORMA CHANGES IN RATE BASE

Pro Forma Changes in Rate Base	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Plant in Service							
Distribution Plant	1,988,703	1,313,058	590,843	25,868	2,286	34,570	22,078
General Plant	120,312	79,437	35,745	1,565	138	2,092	1,335
Common Plant	396,565	261,835	117,820	5,158	456	6,893	4,403
Total Plant	2,505,580	1,654,330	744,408	32,591	2,880	43,555	27,816
Accumulated Reserve							
Distribution Plant	1,306,102	862,365	388,043	16,989	1,501	22,704	14,500
General Plant	(165,156)	(109,046)	(49,068)	(2,148)	(190)	(2,871)	(1,833)
Common Plant	172,547	113,927	51,264	2,244	198	2,999	1,915
Total Accumulated Res	1,313,493	867,246	390,239	17,085	1,509	22,832	14,582
Additions to Rate Base:							
Materials & Supplies	(5,151)	(3,401)	(1,531)	(67)	(6)	(89)	(57)
Prepayments	63,191	41,723	18,774	822	73	1,098	701
Unamortized FAS 106 Costs - Other	(15,863)	(11,331)	(3,980)	(114)	(28)	(252)	(158)
Total Additions	42,177	26,991	13,263	641	39	757	486
Deductions to Rate Base:							
Accumulated Deferred Income Taxes	87,244	57,605	25,920	1,135	100	1,516	968
Accumulated Investment Tax Credits	(13,431)	(8,868)	(3,990)	(175)	(15)	(234)	(149)
Customer Advances	(17,666)	(15,575)	(2,091)	0	0	0	0
Total Adjustments	56,147	33,162	19,839	960	85	1,282	819
Total Rate Base	1,178,117	780,913	347,593	15,187	1,325	20,198	12,901

DOCKET NO. _____
RULE 20:10:13:97
STATEMENT N
SCHEDULE N-1
PAGE 7 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
SUMMARY REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Operating Income and Rate of Return	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Operating Revenues	44,781,444	24,472,863	14,215,030	2,694,155	2,379,550	442,107	577,739
Operating Expenses							
Cost of Gas	34,335,947	17,305,788	11,813,301	2,366,850	2,248,556	199,128	402,324
Other O&M Expense	7,264,810	5,189,160	1,822,777	52,068	12,732	115,546	72,527
Total Operation & Maint. Exp.	41,600,757	22,494,948	13,636,078	2,418,918	2,261,288	314,674	474,851
Depreciation	1,815,586	1,197,824	544,569	22,468	1,315	32,326	17,084
Taxes Other Than Income Taxes	736,253	504,884	202,695	7,547	1,056	12,285	7,786
Fed. & State Inc. Taxes - Current	(1,118,415)	(626,937)	(504,941)	11,425	(26,837)	17,328	11,547
Deferred Income Taxes	997,246	436,935	362,843	92,255	92,357	912	11,944
Total Operating Expenses	44,031,427	24,007,654	14,241,244	2,552,613	2,329,179	377,525	523,212
Operating Income	750,017	465,209	(26,214)	141,542	50,371	64,582	54,527
Rate Base	17,941,816	11,816,826	5,327,387	222,937	28,439	328,346	217,881
Rate of Return	4.180%	3.937%	-0.492%	63.490%	177.119%	19.669%	25.026%

DOCKET NO. _
RULE 20:10:13:
STATEMENT N
SCHEDULE N-1
PAGE 8 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATING REVENUES
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Operating Revenues	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Residential	23,626,622	23,626,622	0	0	0	0	0
Firm General	13,744,983	0	13,744,983	0	0	0	0
Firm Contract	2,612,705	0	0	2,612,705	0	0	0
Air Force	2,283,008	0	0	0	2,283,008	0	0
Small Interruptible	426,064	0	0	0	0	426,064	0
Large Interruptible	558,720	0	0	0	0	0	558,720
Unbilled Revenue	1,312,722	717,078	417,166	79,298	69,291	12,931	16,958
Total Gas Sales and Transport Revenue	44,564,824	24,343,700	14,162,149	2,692,003	2,352,299	438,995	575,678
Other Operating Revenue							
Miscellaneous							
Reconnect Fees	9,276	8,178	1,098	0	0	0	0
NSF Check Fees	5,350	4,717	633	0	0	0	0
Miscellaneous	12,468	8,196	3,721	155	19	227	150
Rent From Gas Property	136,285	89,582	40,673	1,698	211	2,479	1,642
Other Gas Revenues							
Miscellaneous	24,295	17,355	6,096	174	42	386	242
Gas Management Fee	26,869	0	0	0	26,869	0	0
Transport and Penalty Revenue - Net	2,077	1,135	660	125	110	20	27
Total Other Operating Revenue	216,620	129,163	52,881	2,152	27,251	3,112	2,061

DOCKET NO. _____
RULE 20:10:13:
STATEMENT N
SCHEDULE N-1
PAGE 9 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATION & MAINTENANCE EXPENSES
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Operation and Maintenance Expenses	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Cost of Purchased Gas	34,335,947	17,305,788	11,813,301	2,366,850	2,248,556	199,128	402,324
Production Expenses							
Other Gas Supply Expenses	66,813	32,009	21,853	6,251	5,592	251	857
Total Production Expense	66,813	32,009	21,853	6,251	5,592	251	857
Distribution Expenses							
Operation							
Load Dispatch	29,662	12,534	8,557	2,448	2,190	1,555	2,378
Mains and Services	658,165	442,746	189,059	10,657	0	8,944	6,759
Measuring Stations - General	6,404	4,293	1,841	129	0	58	83
Measuring Stations - Industrial	7,023	0	0	0	0	963	6,060
Measuring Stations - City Gate	0	0	0	0	0	0	0
Meters & House Regulators	310,575	195,374	105,124	525	0	9,149	403
Customer Installations	408,227	257,637	138,337	693	0	11,560	0
Other Gas Distribution	607,494	393,252	189,782	5,245	0	13,402	5,813
Rents	17,706	11,461	5,531	153	0	391	170
Supervision & Engineering	419,455	271,527	131,038	3,622	0	9,254	4,014
Total Operation Expense	2,464,711	1,588,824	769,269	23,472	2,190	55,276	25,680
Maintenance							
Structures & Improvements	1,394	838	333	25	171	11	16
Mains	33,232	22,771	9,030	683	0	304	444
Measuring Stations - General	10,888	7,298	3,130	219	0	98	143
Measuring Stations - Industrial	6,089	0	0	0	0	835	5,254
Measuring Stations - City Gate	0	0	0	0	0	0	0
Services	8,505	5,368	2,882	14	0	241	0
Meters & House Regulators	49,002	30,826	16,586	83	0	1,443	64

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATION & MAINTENANCE EXPENSES
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Operation and Maintenance Expenses	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Other Equipment	78,473	48,274	23,042	728	0	2,128	4,301
Supervision & Engineering	66,906	41,159	19,645	620	0	1,814	3,668
Total Maintenance Expense	254,489	156,534	74,648	2,372	171	6,874	13,890
Total Distribution Expenses	2,719,200	1,745,358	843,917	25,844	2,361	62,150	39,570
Customer Accounts	103,835	91,445	12,275	2	2	89	22
Meter Reading	316,275	196,602	105,565	529	0	8,821	4,758
Customer Records & Collection	807,723	711,335	95,487	19	19	694	169
Uncollectible Accounts	139,486	122,841	16,490	3	3	120	29
Miscellaneous Customer Accounts	79,374	69,902	9,383	2	2	68	17
Customer Service & Information	49,845	43,897	5,893	1	1	43	10
Sales Expenses	273,955	241,264	32,387	6	6	235	57
Administration & General Expenses	2,708,304	1,934,507	679,527	19,411	4,746	43,075	27,038
Total Gas O&M Expenses	41,600,757	22,494,948	13,636,078	2,418,918	2,261,288	314,674	474,851
O&M Excl. Gas Cost and A&G	4,556,506	3,254,653	1,143,250	32,657	7,986	72,471	45,489
O&M Excl. Cost of Gas	7,264,810	5,189,160	1,822,777	52,068	12,732	115,546	72,527

DOCKET NO. ____
RULE 20:10:13:9
STATEMENT N
SCHEDULE N-1
PAGE 11 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
DEPRECIATION EXPENSE
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Depreciation Expense	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Distribution Plant							
Mains	772,233	529,133	209,841	15,869	0	7,076	10,314
Structures	914	550	218	16	112	7	11
Meas. & Reg. Sta. General	5,764	3,864	1,657	116	0	52	75
Meas. & Reg. Sta. - City Gate	1,833	0	0	0	770	146	917
Services	453,360	286,121	153,632	769	0	12,838	0
Meters	159,050	100,378	53,898	270	0	4,504	0
Service Regulators	20,498	12,595	6,881	34	0	771	217
Measuring & Reg. Eqpt. - Indust.	1,212	0	0	0	0	166	1,046
Other Property on Cust. Prem.	15,981	10,951	4,343	328	0	146	213
Cathodic Protection & Other Equipment	7,951	5,448	2,161	163	0	73	106
Land Rights	222	152	60	5	0	2	3
Total Distribution Plant	1,439,018	949,192	432,691	17,570	882	25,781	12,902
General Plant	188,470	124,439	55,994	2,451	217	3,276	2,093
Common Plant	188,098	124,193	55,884	2,447	216	3,269	2,089
Gas Plant Leased to Others	0	0	0	0	0	0	0
Total Depreciation Expense	1,815,586	1,197,824	544,569	22,468	1,315	32,326	17,084

DOCKET NO. ___
RULE 20:10:13:
STATEMENT N
SCHEDULE N-1
PAGE 12 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
TAXES OTHER THAN INCOME TAXES
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books **Taxes Other Than Income**	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Ad Valorem Taxes	388,906	256,779	115,544	5,058	447	6,760	4,318
Other Taxes - Payroll, Franchise, Other	347,347	248,105	87,151	2,489	609	5,525	3,468
Total Taxes Other Than Income	736,253	504,884	202,695	7,547	1,056	12,285	7,786

DOCKET NO. ____
RULE 20:10:13:9
STATEMENT N
SCHEDULE N-1
PAGE 13 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
DEFERRED INCOME TAXES
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Deferred Income Taxes	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Other Deferred Income Tax Charges	(464,899)	(306,954)	(138,121)	(6,047)	(534)	(8,082)	(5,161)
Unrecovered Purchased Gas Costs	1,417,682	714,532	487,754	97,724	92,840	8,221	16,611
Closing/Filing and Out of Period	44,463	29,357	13,210	578	51	773	494
Total Gas Charges	997,246	436,935	362,843	92,255	92,357	912	11,944
Accumulated Balance 12/31/03	1,820,407	1,201,939	540,842	23,679	2,092	31,645	20,210

DOCKET NO. ___
RULE 20:10:13:9
STATEMENT N
SCHEDULE N-1
PAGE 14 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
INCOME TAXES
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Income Taxes	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Operating Revenue	44,781,444	24,472,863	14,215,030	2,694,155	2,379,550	442,107	577,739
Operation & Maintenance Expense	41,600,757	22,494,948	13,636,078	2,418,918	2,261,288	314,674	474,851
Depreciation Expense	1,815,586	1,197,824	544,569	22,468	1,315	32,326	17,084
Taxes Other Than Income	736,253	504,884	202,695	7,547	1,056	12,285	7,786
Total Operating Expense	44,152,596	24,197,656	14,383,342	2,448,933	2,263,659	359,285	499,721
Interest Expense	811,985	533,726	242,331	10,115	1,259	14,771	9,783
Total Expenses	44,964,581	24,731,382	14,625,673	2,459,048	2,264,918	374,056	509,504
Taxable Income Before Adjustments	(183,137)	(258,519)	(410,643)	235,107	114,632	68,051	68,235
Tax Deductions							
Purchased Gas Cost Adjustment	2,915,263	1,469,333	1,002,998	200,955	190,912	16,906	34,159
Other Income Tax Charges	(51,616)	(34,080)	(15,335)	(672)	(59)	(897)	(573)
Preferred Dividend Paid Deduction	12,470	8,234	3,704	162	14	217	139
Total Deductions & Adjustments	2,876,117	1,443,487	991,367	200,445	190,867	16,226	33,725
Taxable Income (Before State Income Tax)	(3,059,254)	(1,702,006)	(1,402,010)	34,662	(76,235)	51,825	34,510
Less: State Income Tax	0	0	0	0	0	0	0
Federal Taxable Income	(3,059,254)	(1,702,006)	(1,402,010)	34,662	(76,235)	51,825	34,510

DOCKET NO. _____
RULE 20:10:13:
STATEMENT N
SCHEDULE N-1
PAGE 15 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
INCOME TAXES
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Income Taxes	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Federal Income Tax @ Current Rate	(1,070,738)	(595,702)	(490,703)	12,132	(26,682)	18,139	12,078
Plus: State Income Tax	0	0	0	0	0	0	0
Plus: Credits & Adjustments	(1,539)	(772)	(530)	(107)	(102)	(9)	(19)
Federal and State Income Taxes	(1,072,277)	(596,474)	(491,233)	12,025	(26,784)	18,130	12,059
Rounding & Prior Year Adjustments	(46,138)	(30,463)	(13,708)	(600)	(53)	(802)	(512)
Federal Income Tax Computed	(1,118,415)	(626,937)	(504,941)	11,425	(26,837)	17,328	11,547

DOCKET NO. _____
RULE 20:10:13:
STATEMENT N
SCHEDULE N-1
PAGE 16 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PLANT IN SERVICE
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Plant in Service	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Distribution Plant							
Mains	18,488,541	12,668,303	5,023,944	379,927	0	169,415	246,952
Structures & Improvements	38,555	23,184	9,194	695	4,720	310	452
Meas. & Reg. Sta. Eqpt. - General	251,430	168,557	72,278	5,055	0	2,254	3,286
Meas. & Reg. Sta. Eqpt. - City Gate	68,586	0	0	0	28,811	5,455	34,320
Service Regulators	862,652	530,086	289,579	1,425	0	32,437	9,125
Indust. Meas. & Reg. Sta. Eqpt.	63,429	0	0	0	0	8,699	54,730
Services	5,558,054	3,507,756	1,883,478	9,432	0	157,388	0
Meters	6,163,183	3,889,660	2,088,540	10,459	0	174,524	0
CNG Refueling Station	170,929	117,121	46,447	3,512	0	1,566	2,283
Cathodic Protection & Other Equipment	152,587	102,437	40,624	3,072	3,087	1,370	1,997
Land & Land Rights	38,722	26,533	10,522	795	0	355	517
Total Distribution Plant	31,856,668	21,033,637	9,464,606	414,372	36,618	553,773	353,662
General Plant	9,420,382	6,219,889	2,798,793	122,534	10,828	163,757	104,581
Common Plant	2,478,421	1,636,399	736,338	32,237	2,849	43,083	27,515
Gas Plant Leased to Others	0	0	0	0	0	0	0
Total Gas Plant in Service	43,755,471	28,889,925	12,999,737	569,143	50,295	760,613	485,758

DOCKET NO. _
RULE 20:10:13:
STATEMENT N
SCHEDULE N-1
PAGE 17 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ACCUMULATED RESERVE FOR DEPRECIATION
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Accumulated Reserve for Depreciation	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Distribution Plant							
Mains	13,105,131	8,979,604	3,561,095	269,302	0	120,085	175,045
Structures & Improvements	10,879	6,541	2,594	196	1,332	88	128
Meas. & Reg. Sta. Equip. - General	110,209	73,883	31,681	2,216	0	988	1,441
Meas. & Reg. Sta. Equip. - City Gate	37,475	0	0	0	15,742	2,981	18,752
Services	5,313,048	3,353,130	1,800,452	9,016	0	150,450	0
Meters	2,316,124	1,461,734	784,873	3,931	0	65,586	0
Service Regulators	346,897	213,163	116,448	573	0	13,044	3,669
Indust. Meas. & Reg. Sta. Eqpt.	21,315	0	0	0	0	2,923	18,392
Other Property on Customer Prem.	145,282	99,546	39,478	2,985	0	1,332	1,941
Cathodic Protection & Other Equipment	90,479	61,996	24,586	1,859	0	829	1,209
Land Rights	5,179	3,549	1,408	106	0	47	69
Total Distribution Reserve	21,502,018	14,253,146	6,362,615	290,184	17,074	358,353	220,646
General Plant	2,125,627	1,403,463	631,524	27,648	2,443	36,951	23,598
Common Plant	1,048,054	691,986	311,376	13,633	1,205	18,219	11,635
Gas Plant Leased to Others	(90)	(60)	(27)	(1)	0	(1)	(1)
Total Accumulated Reserve for Depreciation	24,675,609	16,348,535	7,305,488	331,464	20,722	413,522	255,878

DOCKET NO. _
RULE 20:10:13:
STATEMENT N
SCHEDULE N-1
PAGE 18 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
CONSTRUCTION WORK IN PROGRESS
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books CWIP in Service Pending Classification	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
CWIP in Service Pending Classification	324,861	214,493	96,516	4,226	373	5,647	3,606
Total Construction Work in Progress in Service Pending Classification	324,861	214,493	96,516	4,226	373	5,647	3,606

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
WORKING CAPITAL
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Working Capital	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Materials & Supplies	270,692	178,727	80,422	3,521	311	4,706	3,005
Prepaid Insurance	28,707	18,954	8,529	373	33	499	319
Unamortized FAS 106	150,699	107,643	37,811	1,080	264	2,397	1,504

DOCKET NO. _____
RULE 20:10:13:9
STATEMENT N
SCHEDULE N-1
PAGE 20 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
RATE BASE REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

Per Books Rate Base	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Gas Plant in Service	43,755,471	28,889,925	12,999,737	569,143	50,295	760,613	485,758
Less: Accumulated Depreciation	24,675,609	16,348,535	7,305,488	331,464	20,722	413,522	255,878
Net Gas Plant in Service	19,079,862	12,541,390	5,694,249	237,679	29,573	347,091	229,880
CWIP in Service	324,861	214,493	96,516	4,226	373	5,647	3,606
Total Plant	19,404,723	12,755,883	5,790,765	241,905	29,946	352,738	233,486
Additions							
Materials & Supplies	270,692	178,727	80,422	3,521	311	4,706	3,005
Unamortized Gas IRP Costs - Other	150,699	107,643	37,811	1,080	264	2,397	1,504
Prepaid Insurance	28,707	18,954	8,529	373	33	499	319
Total Additions	450,098	305,324	126,762	4,974	608	7,602	4,828
Total Before Deductions	19,854,821	13,061,207	5,917,527	246,879	30,554	360,340	238,314
Deductions							
Accumulated Deferred Income Tax	1,820,407	1,201,939	540,842	23,679	2,092	31,645	20,210
Investment Tax Credit Balance	20,080	13,257	5,966	262	23	349	223
Customer Advances For Constr.	72,518	29,185	43,332	1	0	0	0
Total Deductions	1,913,005	1,244,381	590,140	23,942	2,115	31,994	20,433
Total Rate Base	17,941,816	11,816,826	5,327,387	222,937	28,439	328,346	217,881

DOCKET NO. _____
RULE 20:10:13:
STATEMENT N
SCHEDULE N-1
PAGE 21 OF 21

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

	LINE ITEM		ALLOCATION FACTOR
	PLANT IN SERVICE:		
375	Structures & Improvements	33,835	13 Distribution Mains
		4,720	Direct to Air Force Customer
376	Mains	6,655,875	9 Average Customers @ Distribution
		11,832,666	5 Peak Day @ Distribution
378	Meas. & Reg. Sta. Equip. - General	245,999	13 Distribution Mains
		5,432	Direct to Firm General Customer
379	Meas. & Reg. Sta. Equip. - City Gate	28,811	Direct to Air Force Customer
		5,455	Direct to Small Int. Customer
		34,320	Direct to Large Int. Customer
383	Service Regulators	839,923	10 Weighted Customers Excl AF and LI
		4,951	Direct to Firm General Customer
		8,653	Direct to Small Int. Customer
		9,125	Direct to Large Int. Customer
385	Indust. Meas. & Reg. Sta. Equip.	54,730	Direct to Large Int. Customer
		8,699	Direct to Small Int. Customer
380	Services	5,558,055	10 Weighted Customers Excl AF and LI
381	Meters	6,163,183	10 Weighted Customers Excl AF and LI
		0	Direct to Firm Contract
386	Other Property on Customer Premise	170,931	13 Distribution Mains
387	Cathodic Protection & Other Equipment	149,500	13 Distribution Mains
		3,087	Direct to Air Force Customer
374	Land & Land Rights	38,723	13 Distribution Mains
389	Total General Plant	9,420,384	15 Distribution Plant
389	Total Common Plant	2,478,421	15 Distribution Plant
386.3	Gas Plant Leased to Others	0	15 Distribution Plant
	ACCUMULATED RESERVE FOR DEPRECIATION REPORT:		
375	Structures & Improvements	10,877	17 Structures & Improvements
376	Mains	13,105,131	13 Distribution Mains
378	Meas. & Reg. Sta. Equip. - General	110,209	18 Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. Equip. - City Gate	37,475	19 Meas. & Reg. Eqpt.- City Gate
380	Services	5,313,049	10 Weighted Customers Excl AF and LI
381	Meters	2,316,123	10 Weighted Customers Excl AF and LI
383	Service Regulators	346,898	20 Service Regulators
385	Indust. Meas. & Reg. Sta. Equip.	21,315	21 Ind. Meas. & Reg. Sta. Eqpt.
386	Other Property on Customer's Premises	145,281	13 Distribution Mains
387	Cathodic Protection & Other Equipment	90,478	13 Distribution Mains
374	Land Rights	5,180	13 Distribution Mains
	Total General Plant	2,125,627	15 Distribution Plant
	Total Common Plant	1,048,052	15 Distribution Plant
386.3	Gas Plant Leased to Others	(91)	15 Distribution Plant
	CONSTRUCTION WORK IN PROGRESS REPORT:		
	CWIP in Service pending Classification	324,862	15 Distribution Plant

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

	LINE ITEM		ALLOCATION FACTOR
	OPERATING REVENUE REPORT:		
	Residential	4,389,654	Direct to Residential Demand
		15,910,084	Direct to Residential Energy
		3,326,884	Direct to Residential Customer
	Firm General	2,996,472	Direct to Firm General Demand
		10,002,685	Direct to Firm General Energy
		745,826	Direct to Firm General Customer
	Firm Contract	225,483	Direct to Firm Contract Demand
		2,385,422	Direct to Firm Contract Energy
		1,800	Direct to Firm Contract Customer
	Air Force	228,923	Direct to Air Force Demand
		2,052,945	Direct to Air Force Energy
		1,140	Direct to Air Force Customer
	Small Interruptible	50,509	Direct to Small Int. Demand
		327,555	Direct to Small Int. Energy
		48,000	Direct to Small Int. Customer
	Large Interruptible	37,068	Direct to Large Int. Demand
		491,052	Direct to Large Int. Energy
		30,600	Direct to Large Int. Customer
	Unbilled Revenue	1,312,719	26 Sales Revenue
	Other Operating Revenue		
	Reconnect Fees	9,276	11 Average Res. & Firm General Cust.
	NSF Check Fees	5,350	11 Average Res. & Firm General Cust.
	Miscellaneous	12,469	24 Net Gas Plant in Service
	Rent From Gas Property	136,285	24 Net Gas Plant in Service
	Other Gas Revenues		
	Miscellaneous Revenues	24,296	31 O&M Excl. Cost of Gas
	Gas Management Fee	26,869	Direct to Air Force Energy
	Transport & Sales Penalty Revenue - Net	2,076	23 Sales & Transportation Rev.
	OPERATION & MAINTENANCE EXPENSE REPORT:		
	Cost of Purchased Gas	4,389,654	Direct to Residential Demand
		12,916,134	Direct to Residential Energy
		2,996,472	Direct to Firm General Demand
		8,816,829	Direct to Firm General Energy
		225,483	Direct to Firm Contract Demand
		2,141,367	Direct to Firm Contract Energy
		228,923	Direct to Air Force Demand
		2,019,633	Direct to Air Force Energy
		50,509	Direct to Small Int. Demand
		148,619	Direct to Small Int. Energy
		37,068	Direct to Large Int. Demand
		365,256	Direct to Large Int. Energy
813	Other Gas Supply Expenses	66,813	3 Dk Sales
870	Operation Supervision & Maintenance	419,454	27 All Other Dist. Operation Exp.
871	Load Dispatch	29,661	1 Dk Throughput
874	Mains & Services	658,166	22 Mains & Services
875	Measuring Stations - General	6,403	18 Meas. & Reg. Sta. Eqpt.- General
876	Measuring Stations - Industrial	7,023	21 Ind. Meas. & Reg. Sta. Eqpt.
877	Measuring Stations - City Gate	0	19 Meas. & Reg. Eqpt.- City Gate
878	Meters & House Regulators	310,576	16 Meters & Regulators
879	Customer Installations	408,227	10 Weighted Customers Excl AF and LI
880	Other Gas Distribution	607,494	27 All Other Dist. Operation Exp.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

	LINE ITEM		ALLOCATION FACTOR
881	Rents	17,705	27 All Other Dist. Operation Exp.
885	Maintenance Supervision & Engineering	66,907	28 All Other Dist. Maintenance Exp.
886	Structures & Improvements	1,394	17 Structures & Improvements
887	Mains	33,233	13 Distribution Mains
889	Measuring Stations - General	10,887	18 Meas. & Reg. Sta. Eqpt.- General
890	Measuring Stations - Industrial	6,089	21 Ind. Meas. & Reg. Sta. Eqpt.
891	Measuring Stations - City Gate	0	19 Meas. & Reg. Eqpt.- City Gate
892	Services	8,505	10 Weighted Customers Excl AF and LI
893	Meters & House Regulators	49,002	16 Meters & Regulators
894	Other Equipment	78,473	28 All Other Dist. Maintenance Exp.
901	Customer Accounts	103,836	8 Average Customers
902	Meter Reading	316,275	41 Total Weighted Customers
903	Customer Records & Collection	807,722	8 Average Customers
904	Uncollectible Accounts	139,486	8 Average Customers
905	Miscellaneous Customer Accounts	79,374	8 Average Customers
907	Customer Service & Info.	49,845	8 Average Customers
911	Sales Expenses	273,956	8 Average Customers
920	Administration & General	2,708,304	30 O&M Excl. Gas Cost and A&G
	DEPRECIATION EXPENSE REPORT:		
376	Mains	772,234	13 Distribution Mains
375	Structures	914	17 Structures & Improvements
378	Meas. & Reg. Sta. - General	5,764	18 Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. - City Gate	1,832	19 Meas. & Reg. Eqpt.- City Gate
380	Services	453,360	10 Weighted Customers Excl AF and LI
381	Meters	159,050	10 Weighted Customers Excl AF and LI
383	Service Regulators	20,497	20 Service Regulators
385	Measuring & Reg. Equip. - Indust.	1,212	21 Ind. Meas. & Reg. Sta. Eqpt.
386	Other Property on Customer's Premises	15,982	13 Distribution Mains
387	Cathodic Protection & Other Equipment	7,950	13 Distribution Mains
374	Land Rights	222	13 Distribution Mains
	Total General Plant	188,470	15 Distribution Plant
	Total Common Plant	188,097	15 Distribution Plant
386.3	Gas Plant Leased to Others	0	15 Distribution Plant
	TAXES OTHER THAN INCOME REPORT:		
	Ad Valorem Taxes	388,906	15 Distribution Plant
	Other Taxes - Payroll, Franchise, Other	347,346	31 O&M Excl. Cost of Gas
	DEFERRED INCOME TAXES REPORT:		
	Other Deferred Income Tax Charges	(464,900)	25 Total Gas Plant in Service
	Unrecovered Purchased Gas Costs	1,417,683	33 Total Cost of Gas
	Closing/Filing, Out of Period & Fed/State FAS 109	44,463	25 Total Gas Plant in Service
	Accumulated Balance 12/31/03	1,820,406	25 Total Gas Plant in Service

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

LINE ITEM		ALLOCATION FACTOR
INCOME TAXES REPORT:		
Interest Charges	811,985	24 Net Gas Plant in Service
Purchased Gas Cost Adjustment	2,915,264	33 Total Cost of Gas
Other Income Tax Charges	(51,616)	25 Total Gas Plant in Service
Preferred Dividend Paid Deduction	12,470	25 Total Gas Plant in Service
State Income Tax	0	35 Taxable Income
Rounding & Prior Year Adjustments	(46,139)	25 Total Gas Plant in Service
Taxable Income @ Federal Tax Rate	35.00%	Direct Input
Credits & Adjustments	(1,537)	40 Total Tax Deductions & Adjustments
WORKING CAPITAL REPORT:		
Materials & Supplies	270,692	15 Distribution Plant
Prepaid Insurance	28,708	25 Total Gas Plant in Service
Unamortized FAS 106 Costs - Other	150,700	31 O&M Excl. Cost of Gas
RATE BASE REPORT:		
Investment Tax Credit Balance	20,079	25 Total Gas Plant in Service
Customer Advances for Const.	33,104	11 Average Res. & Firm General Cust.
	5,441	Direct to Firm General
	16,068	Direct to Firm General
	17,905	Direct to Firm General
COST OF SERVICE BY COMPONENT REPORT:		
Operating Income for Proposed Return	9.613%	
Related Taxes for Increase		
Inverse Tax Rate for Federal & State Income	65.000%	
Effective Federal Tax Rate	35.000%	
Gross Receipts Tax Rate	0.15%	
Inverse of Combined Tax Rate	64.85%	
Billing Units @ Customer		
Dk Throughput (Pro Forma 2004)	3,280,458	Direct to Residential Energy
	2,239,643	Direct to Firm General Energy
	640,689	Direct to Firm Contract Energy
	573,102	Direct to Air Force Energy
	406,921	Direct to Small Int. Energy
	622,478	Direct to Large Int. Energy
Bills (Average Customers * 12)	455,196	Direct to Residential Customer
	61,104	Direct to Firm General Customer
	12	Direct to Firm Contract Customer
	12	Direct to Air Force Customer
	444	Direct to Small Int. Customer
	108	Direct to Large Int. Customer

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

LINE ITEM		ALLOCATION FACTOR
ADJUSTMENTS TO OPERATING INCOME:		
Revenue:		
Pro Forma 2004 @ Current Rates		
Residential	334,639	Direct to Residential Demand
	6,957,555	Direct to Residential Energy
	134,502	Direct to Residential Customer
Firm General	228,910	Direct to Firm General Demand
	4,810,020	Direct to Firm General Energy
	34,208	Direct to Firm General Customer
Firm Contract	49,975	Direct to Firm Contract Demand
	1,219,774	Direct to Firm Contract Energy
	0	Direct to Firm Contract Customer
Air Force	15,219	Direct to Air Force Demand
	974,179	Direct to Air Force Energy
	0	Direct to Air Force Customer
Small Interruptible	(13,427)	Direct to Small Int Demand
	(7,839)	Direct to Small Int Energy
	1,200	Direct to Small Int Customer
Large Interruptible	673	Direct to Large Int Demand
	82,567	Direct to Large Int Energy
	(9,600)	Direct to Large Int Customer
Unbilled Revenues	(1,312,719)	26 Sales Revenue
Late Payment Penalty Revenue	47,709	26 Sales Revenue
Cost of Gas		
Current Cost of Purchased Gas	334,639	Direct to Residential Demand
	5,244,481	Direct to Residential Energy
	228,910	Direct to Firm General Demand
	3,581,835	Direct to Firm General Energy
	49,975	Direct to Firm Contract Demand
	1,240,830	Direct to Firm Contract Energy
	15,219	Direct to Air Force Demand
	971,959	Direct to Air Force Energy
	(13,427)	Direct to Small Int Demand
	(6,084)	Direct to Small Int Energy
	673	Direct to Large Int Demand
	98,177	Direct to Large Int Energy
Other O&M Expense		
Labor Expense		
Other Gas Supply	4,028	30 O&M Excl. Cost of Gas and A&G
Distribution	135,355	39 Distribution O&M
Customer Accounts	60,016	38 Customer Expense Accounts O&M
Customer Service & Information	2,188	8 Average Customers
Sales	14,552	8 Average Customers
Administrative & General	58,951	30 O&M Excl. Cost of Gas and A&G
Benefits Expense	546,843	30 O&M Excl. Cost of Gas and A&G
Insurance Expense	(44,184)	30 O&M Excl. Cost of Gas and A&G
Advertising Expense	(26,643)	8 Average Customers
Postage Expense	(4,692)	8 Average Customers
Industry Dues	(18,359)	30 O&M Excl. Cost of Gas and A&G
Regulatory Commission Expense	154,437	30 O&M Excl. Cost of Gas and A&G
All Other O&M	369,887	31 O&M Excl Cost of Gas

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

LINE ITEM		ALLOCATION FACTOR
Depreciation Expense	26,763	15 Distribution Plant
Taxes Other Than Income		
Ad Valorem Taxes	25,924	15 Distribution Plant
Other Taxes - Payroll, Franchise, Other	65,661	31 O&M Excl Cost of Gas
Current Income Taxes		
Interest Expense	(60,189)	24 Net Gas Plant in Service
Tax Depreciation on Plant Additions	171,814	25 Total Gas Plant in Service
Income Taxes on Pro Forma Adjustments	111,302	25 Total Gas Plant in Service
Elimination of Closing/Filing and Reserve Adjustment	46,139	25 Total Gas Plant in Service
Deferred Income Taxes		
Deferred Income Taxes on Plant Additions	60,135	25 Total Gas Plant in Service
Elimination of Closing/Filing, Out of Period	(44,463)	25 Total Gas Plant in Service
ADJUSTMENTS TO RATE BASE:		
Plant in Service		
Distribution Plant	1,988,703	15 Distribution Plant
General Plant	120,312	15 Distribution Plant
Common Plant	396,565	15 Distribution Plant
Accumulated Reserve		
Distribution Plant	1,306,102	15 Distribution Plant
General Plant	(165,156)	15 Distribution Plant
Common Plant	172,549	15 Distribution Plant
Additions to Rate Base:		
Materials & Supplies	(5,151)	15 Distributin Plant
Prepayments	63,192	25 Total Gas Plant in Service
Unamortized FAS 106 Costs - Other	(15,864)	31 O&M Excl. Cost of Gas
Deductions to Rate Base:		
Accumulated Deferred Income taxes	87,245	25 Total Gas Plant in Service
Accumulated Investment Tax Credits	(13,430)	25 Total Gas Plant in Service
Customer Advances	(17,666)	11 Average Res & Firm Gneral Customers

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		Total	Residential			Firm General		
		South Dakota	Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput	7,763,291		3,280,458			2,239,643	
		100.000000%	0.000000%	42.256023%	0.000000%	0.000000%	28.849144%	0.000000%
2.	1-Day Peak Sales	57,969	31,872			20,096		
		100.000000%	54.981111%	0.000000%	0.000000%	34.666805%	0.000000%	0.000000%
3.	Dk Sales	6,847,427		3,280,458			2,239,643	
		100.000000%	0.000000%	47.907893%	0.000000%	0.000000%	32.707804%	0.000000%
4.	Dk Throughput @ Distribution	6,608,700		3,138,051			2,085,435	
		100.000000%	0.000000%	47.483634%	0.000000%	0.000000%	31.555904%	0.000000%
5.	1-Day Peak @ Distribution	54,682	31,423			19,609		
		100.000000%	57.464979%	0.000000%	0.000000%	35.860064%	0.000000%	0.000000%
8.	Average Customers	43,073			37,933			5,092
		100.000000%	0.000000%	0.000000%	88.066769%	0.000000%	0.000000%	11.821791%
9.	Average Customers @ Distribution	41,159			36,291			4,828
		100.000000%	0.000000%	0.000000%	88.172696%	0.000000%	0.000000%	11.730120%
10.	Weighted Customers Excl. AF and LI	60,105			37,933			20,368
		100.000000%	0.000000%	0.000000%	63.111222%	0.000000%	0.000000%	33.887364%
11.	Average Res. & Firm General Cust.	43,026			37,933			5,092
		100.000000%	0.000000%	0.000000%	88.162971%	0.000000%	0.000000%	11.834705%
12.	Weighted Customers @ Distribution	57,891			36,291			19,312
		100.000000%	0.000000%	0.000000%	62.688501%	0.000000%	0.000000%	33.359244%
13	Distribution Mains	18,488,541	6,799,639	0	5,868,664	4,243,202	0	780,742
		100.000000%	36.777586%	0.000000%	31.742169%	22.950443%	0.000000%	4.222843%

DOCKET NO. _____
RULE 20:10:13:
STATEMENT N
SCHEDULE N-3
PAGE 1 OF 9

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		Firm Contract			Air Force		
		Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput		640,689			573,102	
		0.000000%	8.252802%	0.000000%	0.000000%	7.382204%	0.000000%
2.	1-Day Peak Sales	1,755			1,570		
		3.027480%	0.000000%	0.000000%	2.708344%	0.000000%	0.000000%
3.	Dk Sales		640,689			573,102	
		0.000000%	9.356639%	0.000000%	0.000000%	8.369596%	0.000000%
4.	Dk Throughput @ Distribution		640,689			0	
		0.000000%	9.694630%	0.000000%	0.000000%	0.000000%	0.000000%
5.	1-Day Peak @ Distribution	1,755			0		
		3.209466%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
8.	Average Customers			1			1
		0.000000%	0.000000%	0.002322%	0.000000%	0.000000%	0.002322%
9.	Average Customers @ Distribution			1			0
		0.000000%	0.000000%	0.002430%	0.000000%	0.000000%	0.000000%
10.	Weighted Customers Excl. AF and LI			102			0
		0.000000%	0.000000%	0.169703%	0.000000%	0.000000%	0.000000%
11.	Average Res. & Firm General Cust.			1			0
		0.000000%	0.000000%	0.002324%	0.000000%	0.000000%	0.000000%
12.	Weighted Customers @ Distribution			102			0
		0.000000%	0.000000%	0.176193%	0.000000%	0.000000%	0.000000%
13	Distribution Mains	379,765	0	162	0	0	0
		2.054056%	0.000000%	0.000876%	0.000000%	0.000000%	0.000000%

DOCKET NO. RULE 20:10:13:9
STATEMENT N
SCHEDULE N-3
PAGE 2 OF 9

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		Small Interruptible			Large Interruptible		
		Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput		406,921			622,478	
		0.000000%	5.241604%	0.000000%	0.000000%	8.018223%	0.000000%
2.	1-Day Peak Sales	971			1,705		
		1.675033%	0.000000%	0.000000%	2.941227%	0.000000%	0.000000%
3.	Dk Sales		25,747			87,788	
		0.000000%	0.376010%	0.000000%	0.000000%	1.282058%	0.000000%
4.	Dk Throughput @ Distribution		329,613			414,912	
		0.000000%	4.987562%	0.000000%	0.000000%	6.278270%	0.000000%
5.	1-Day Peak @ Distribution	759			1,136		
		1.388025%	0.000000%	0.000000%	2.077466%	0.000000%	0.000000%
8.	Average Customers			37			9
		0.000000%	0.000000%	0.085901%	0.000000%	0.000000%	0.020895%
9.	Average Customers @ Distribution			32			7
		0.000000%	0.000000%	0.077747%	0.000000%	0.000000%	0.017007%
10.	Weighted Customers Excl. AF and LI			1,702			0
		0.000000%	0.000000%	2.831711%	0.000000%	0.000000%	0.000000%
11.	Average Res. & Firm General Cust.			0			0
		0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12.	Weighted Customers @ Distribution			1,472			714
		0.000000%	0.000000%	2.542710%	0.000000%	0.000000%	1.233352%
13	Distribution Mains	164,240	0	5,175	245,820	0	1,132
		0.888334%	0.000000%	0.027990%	1.329580%	0.000000%	0.006123%

DOCKET NO. _
RULE 20:10:13:
STATEMENT N
SCHEDULE N-3
PAGE 3 OF 9

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		Total	Residential			Firm General		
		South Dakota	Demand	Energy	Customer	Demand	Energy	Customer
15.	Distribution Plant	31,856,668 100.000000%	7,034,642 22.082165%	0 0.000000%	13,998,995 43.943689%	4,389,852 13.780010%	0 0.000000%	5,074,754 15.929959%
16.	Meters & Regulators	7,025,835 100.000000%	0 0.000000%	0 0.000000%	4,419,746 62.907056%	0 0.000000%	0 0.000000%	2,378,119 33.848205%
17.	Structures & Improvements	38,555 100.000000%	12,444 32.275970%	0 0.000000%	10,740 27.856309%	7,765 20.140060%	0 0.000000%	1,429 3.706393%
18.	Meas. & Reg. Sta. Eqpt.- General	251,430 100.000000%	90,472 35.982977%	0 0.000000%	78,085 31.056358%	56,458 22.454759%	0 0.000000%	15,820 6.292010%
19.	Meas. & Reg. Eqpt.- City Gate	68,586 100.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%
20.	Service Regulators	862,652 100.000000%	0 0.000000%	0 0.000000%	530,086 61.448417%	0 0.000000%	0 0.000000%	289,579 33.568461%
21.	Ind. Meas. & Reg. Sta. Eqpt.	63,429 100.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%
22.	Mains & Services	24,046,595 100.000000%	6,799,639 28.276931%	0 0.000000%	9,376,420 38.992714%	4,243,202 17.645750%	0 0.000000%	2,664,220 11.079406%
23.	Sales & Transportation Rev.	44,564,824 100.000000%	4,522,882 10.148996%	16,392,962 36.784532%	3,427,856 7.691842%	3,087,416 6.927921%	10,306,271 23.126471%	768,462 1.724369%
24.	Net Gas Plant in Service	19,079,862 100.000000%	4,009,829 21.016027%	0 0.000000%	8,531,561 44.715004%	2,502,267 13.114702%	0 0.000000%	3,191,982 16.729586%
25.	Total Gas Plant in Service	43,755,471 100.000000%	9,662,156 22.082165%	0 0.000000%	19,227,769 43.943691%	6,029,509 13.780012%	0 0.000000%	6,970,228 15.929958%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		Firm Contract			Air Force		
		Demand	Energy	Customer	Demand	Energy	Customer
15.	Distribution Plant	392,890 1.233305%	0 0.000000%	21,482 0.067433%	0 0.000000%	0 0.000000%	36,618 0.114946%
16.	Meters & Regulators	0 0.000000%	0 0.000000%	11,884 0.169147%	0 0.000000%	0 0.000000%	0 0.000000%
17.	Structures & Improvements	695 1.802620%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	4,720 12.242251%
18.	Meas. & Reg. Sta. Eqpt.- General	5,053 2.009704%	0 0.000000%	2 0.000795%	0 0.000000%	0 0.000000%	0 0.000000%
19.	Meas. & Reg. Eqpt.- City Gate	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	28,811 42.007115%
20.	Service Regulators	0 0.000000%	0 0.000000%	1,425 0.165188%	0 0.000000%	0 0.000000%	0 0.000000%
21.	Ind. Meas. & Reg. Sta. Eqpt.	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%
22.	Mains & Services	379,765 1.579288%	0 0.000000%	9,594 0.039898%	0 0.000000%	0 0.000000%	0 0.000000%
23.	Sales & Transportation Rev.	232,327 0.521324%	2,457,821 5.515159%	1,855 0.004162%	235,871 0.529276%	2,115,253 4.746463%	1,175 0.002637%
24.	Net Gas Plant in Service	223,952 1.173761%	0 0.000000%	13,727 0.071945%	0 0.000000%	0 0.000000%	29,573 0.154996%
25.	Total Gas Plant in Service	539,638 1.233304%	0 0.000000%	29,505 0.067432%	0 0.000000%	0 0.000000%	50,295 0.114946%

DOCKET NO. _____
RULE 20:10:13:5
STATEMENT N
SCHEDULE N-3
PAGE 5 OF 9

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		Small Interruptible			Large Interruptible		
		Demand	Energy	Customer	Demand	Energy	Customer
15.	Distribution Plant	169,916 0.533377%	0 0.000000%	383,857 1.204951%	254,317 0.798316%	0 0.000000%	99,345 0.311849%
16.	Meters & Regulators	0 0.000000%	0 0.000000%	206,961 2.945714%	0 0.000000%	0 0.000000%	9,125 0.129878%
17.	Structures & Improvements	301 0.780703%	0 0.000000%	9 0.023343%	450 1.167164%	0 0.000000%	2 0.005187%
18.	Meas. & Reg. Sta. Eqpt.- General	2,185 0.869029%	0 0.000000%	69 0.027443%	3,271 1.300959%	0 0.000000%	15 0.005966%
19.	Meas. & Reg. Eqpt.- City Gate	0 0.000000%	0 0.000000%	5,455 7.953534%	0 0.000000%	0 0.000000%	34,320 50.039351%
20.	Service Regulators	0 0.000000%	0 0.000000%	32,437 3.760149%	0 0.000000%	0 0.000000%	9,125 1.057785%
21.	Ind. Meas. & Reg. Sta. Eqpt.	0 0.000000%	0 0.000000%	8,699 13.714970%	0 0.000000%	0 0.000000%	54,730 86.285030%
22.	Mains & Services	164,240 0.683007%	0 0.000000%	162,563 0.676033%	245,820 1.022265%	0 0.000000%	1,132 0.004708%
23.	Sales & Transportation Rev.	52,042 0.116778%	337,496 0.757315%	49,457 0.110978%	38,193 0.085702%	505,956 1.135326%	31,529 0.070749%
24.	Net Gas Plant in Service	96,852 0.507614%	0 0.000000%	250,239 1.311536%	144,964 0.759775%	0 0.000000%	84,916 0.445054%
25.	Total Gas Plant in Service	233,381 0.533376%	0 0.000000%	527,232 1.204952%	349,307 0.798316%	0 0.000000%	136,451 0.311848%

DOCKET NO. _____
RULE 20:10:13:9
STATEMENT N
SCHEDULE N-3
PAGE 6 OF 9

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		Total	Residential			Firm General		
		South Dakota	Demand	Energy	Customer	Demand	Energy	Customer
26.	Sales Revenue	43,252,102	4,389,654	15,910,084	3,326,884	2,996,472	10,002,685	745,826
		100.000000%	10.148995%	36.784534%	7.691844%	6.927922%	23.126471%	1.724369%
27.	All Other Dist. Operation Exp.	1,390,394	188,413	0	711,637	117,576	0	316,785
		100.000001%	13.551051%	0.000000%	51.182399%	8.456308%	0.000000%	22.783830%
28.	All Other Dist. Maintenance Exp.	107,716	16,139	0	50,124	10,072	0	21,556
		100.000000%	14.982919%	0.000000%	46.533477%	9.350514%	0.000000%	20.011883%
30.	O&M Excl. Gas Cost and A&G	4,556,506	368,346	44,543	2,841,764	229,862	30,410	882,978
		99.999998%	8.083957%	0.977569%	62.367173%	5.044699%	0.667397%	19.378401%
31.	O&M Excl. Cost of Gas	7,264,810	587,284	71,019	4,530,857	366,488	48,485	1,407,804
		100.000000%	8.083957%	0.977575%	62.367178%	5.044702%	0.667395%	19.378401%
33.	Total Cost of Gas	34,335,947	4,389,654	12,916,134	0	2,996,472	8,816,829	0
		100.000000%	12.784427%	37.616945%	0.000000%	8.726924%	25.678130%	0.000000%
35.	Taxable Income	(3,059,254)	(1,447,696)	2,306,782	(2,561,092)	(917,431)	690,696	(1,175,275)
		100.000000%	47.321864%	-75.403415%	83.716226%	29.988716%	-22.577269%	38.417045%
38.	Customer Account Expense O&M	103,835	0	0	91,445	0	0	12,275
		100.000000%	0.000000%	0.000000%	88.067608%	0.000000%	0.000000%	11.821640%
39.	Distribution O&M	2,719,200	368,346	12,534	1,364,478	229,862	8,557	605,498
		100.000003%	13.546119%	0.460944%	50.179391%	8.453295%	0.314688%	22.267505%
40.	Total Tax Deductions & Adjustments	2,876,117	364,056	1,096,633	(17,202)	249,018	748,585	(6,236)
		100.000000%	12.657900%	38.128943%	-0.598098%	8.658132%	26.027627%	-0.216820%
41.	Total Weighted Customers	61,023	0	0	37,933	0	0	20,368
		100.000000%	0.000000%	0.000000%	62.161808%	0.000000%	0.000000%	33.377579%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		Firm Contract			Air Force		
		Demand	Energy	Customer	Demand	Energy	Customer
26.	Sales Revenue	225,483 0.521323%	2,385,422 5.515159%	1,800 0.004162%	228,923 0.529276%	2,052,945 4.746463%	1,140 0.002636%
27.	All Other Dist. Operation Exp.	10,523 0.756836%	0 0.000000%	1,481 0.106517%	0 0.000000%	0 0.000000%	0 0.000000%
28.	All Other Dist. Maintenance Exp.	902 0.837387%	0 0.000000%	97 0.090052%	0 0.000000%	0 0.000000%	0 0.000000%
30.	O&M Excl. Gas Cost and A&G	20,574 0.451530%	8,699 0.190914%	3,384 0.074267%	0 0.000000%	7,782 0.170789%	204 0.004477%
31.	O&M Excl. Cost of Gas	32,803 0.451533%	13,870 0.190920%	5,395 0.074262%	0 0.000000%	12,407 0.170782%	325 0.004474%
33.	Total Cost of Gas	225,483 0.656697%	2,141,367 6.236516%	0 0.000000%	228,923 0.666715%	2,019,633 5.881978%	0 0.000000%
35.	Taxable Income	(79,782) 2.607891%	120,270 -3.931351%	(5,826) 0.190439%	(12,478) 0.407877%	(61,846) 2.021604%	(1,911) 0.062466%
38.	Customer Account Expense O&M	0 0.000000%	0 0.000000%	2 0.001926%	0 0.000000%	0 0.000000%	2 0.001926%
39.	Distribution O&M	20,574 0.756620%	2,448 0.090026%	2,822 0.103781%	0 0.000000%	2,190 0.080538%	171 0.006289%
40.	Total Tax Deductions & Adjustments	18,661 0.648826%	181,811 6.321405%	(27) -0.000939%	19,437 0.675807%	171,475 5.962031%	(45) -0.001565%
41.	Total Weighted Customers	0 0.000000%	0 0.000000%	102 0.167150%	0 0.000000%	0 0.000000%	0 0.000000%

DOCKET NO. _____
RULE 20:10:13:9
STATEMENT N
SCHEDULE N-3
PAGE 8 OF 9

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2003

		Small Interruptible			Large Interruptible		
		Demand	Energy	Customer	Demand	Energy	Customer
26.	Sales Revenue	50,509 0.116778%	327,555 0.757316%	48,000 0.110977%	37,068 0.085702%	491,052 1.135325%	30,600 0.070748%
27.	All Other Dist. Operation Exp.	4,551 0.327317%	0 0.000000%	26,123 1.878820%	6,811 0.489861%	0 0.000000%	6,494 0.467062%
28.	All Other Dist. Maintenance Exp.	390 0.362063%	0 0.000000%	2,531 2.349697%	584 0.542166%	0 0.000000%	5,321 4.939842%
30.	O&M Excl. Gas Cost and A&G	8,897 0.195259%	1,806 0.039636%	61,768 1.355600%	13,317 0.292263%	3,235 0.070997%	28,937 0.635070%
31.	O&M Excl. Cost of Gas	14,185 0.195256%	2,879 0.039629%	98,482 1.355603%	21,232 0.292258%	5,158 0.071000%	46,137 0.635075%
33.	Total Cost of Gas	50,509 0.147102%	148,619 0.432838%	0 0.000000%	37,068 0.107957%	365,256 1.063771%	0 0.000000%
35.	Taxable Income	(31,942) 1.044111%	173,268 -5.663734%	(89,501) 2.925583%	(45,709) 1.494122%	104,324 -3.410112%	(24,105) 0.787937%
38.	Customer Account Expense O&M	0 0.000000%	0 0.000000%	89 0.085713%	0 0.000000%	0 0.000000%	22 0.021187%
39.	Distribution O&M	8,897 0.327192%	1,555 0.057186%	51,698 1.901221%	13,317 0.489740%	2,378 0.087452%	23,875 0.878016%
40.	Total Tax Deductions & Adjustments	4,080 0.141858%	12,618 0.438717%	(472) -0.016411%	2,835 0.098570%	31,012 1.078259%	(122) -0.004242%
41.	Total Weighted Customers	0 0.000000%	0 0.000000%	1,702 2.789112%	0 0.000000%	0 0.000000%	918 1.504351%

DOCKET NO. _____
RULE 20:10:13:97
STATEMENT N
SCHEDULE N-3
PAGE 9 OF 9

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - SOUTH DAKOTA

Customer Class/Rate	Pro Forma 2004 1/ Customers	Dk	Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	37,933	3,280,458	$31,053,318	$31,949,560	$896,242	2.9%
Firm General Service - Rates 70 & 72	5,092	2,239,643	18,818,121	19,196,861	378,740	2.0%
Firm Contract Service Rate	1	640,689	3,882,454	3,882,454	0	0.0%
Air Force Service - Rate 64	1	573,102	3,272,406	3,272,406	0	0.0%
Small Interruptible						
Sales - Rate 71	7	25,747	195,054			
Transport - Rate 81	30	381,174	210,944			
Total Small Interruptible	37	406,921	405,998	405,998	0	0.0%
Large Interruptible						
Sales - Rate 85	1	87,788	518,520			
Transport - Rate 82	8	534,690	113,840			
	9	622,478	632,360	638,795	6,435	1.0%
Total South Dakota	43,073	7,763,291	$58,064,657	$59,346,074	$1,281,417	2.2%

1/ Rule 20:10:13:85 Statement I, Page 3.

DOCKET NO. _____
RULE 20:10:13:98
STATEMENT O
PAGE 1 OF 1

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION OF REVENUES
Pro Forma 2004

	Billing Determinants					Embedded COS Before Increase		
Rate Class	Bills	Dk	Distribution Revenues	Gas Costs	Total Revenues	Operating Income	Rate Base	Rate Of Return
Residential	455,196	3,280,458	$8,168,843	$22,884,475	$31,053,318	$568,917	$12,597,739	4.52%
Firm General Service	61,104	2,239,643	3,194,371	15,623,750	18,818,121	299,809	5,674,980	5.28%
Firm Contract	12	640,689	224,760	3,657,694	3,882,454	71,321	238,124	29.95%
Air Force	12	573,102	36,672	3,235,734	3,272,406	6,964	29,764	23.40%
Small Interruptible								
Sales	84	25,747	15,443	179,611	195,054			
Transportation	360	381,174	210,944	0	210,944			
Total Small IT	444	406,921	226,387	179,611	405,998	41,320	348,544	11.86%
Large Interruptible								
Sales	12	87,788	17,338	501,182	518,520			
Transportation	96	534,690	113,840	0	113,840			
Total Large IT	108	622,478	131,178	501,182	632,360	18,201	230,782	7.89%
Total South Dakota	516,876	7,763,291	$11,982,211	$46,082,446	$58,064,657	$1,006,532	$19,119,933	5.26%

	Target Rate Design -Distribution Revenues				Rate Design Results			
Rate Class	Increase In Revenue	% Increase	Operating Income	Rate Of Return	Increase In Revenue	Total Revenues	% Incr	Rate Of Return
Residential	$897,073	2.89%	$1,150,669	9.13%	$896,242	$31,949,560	2.89%	9.13%
Firm General Service	378,916	2.01%	545,536	9.61%	378,740	19,196,861	2.01%	9.61%
Firm Contract	0	0.00%	71,321	29.95%	0	3,882,454	0.00%	29.95%
Air Force	0	0.00%	6,964	23.40%	0	3,272,406	0.00%	23.40%
Small Interruptible								
Sales								
Transportation								
Total Small IT	0	0.00%	41,320	11.86%	0	405,998	0.00%	11.86%
Large Interruptible								
Sales								
Transportation								
Total Large IT	6,144	0.97%	22,185	9.61%	6,435	638,795	1.02%	9.69%
Total South Dakota	$1,282,133	2.21%	$1,837,995	9.61%	$1,281,417	$59,346,074	2.21%	9.61%

Cost of Gas (Adjusted for Losses)		5/1/04	
Pro Forma	COG	Surcharge	Total
Firm	$6.976	$0.395	$7.371
Interruptible - Small	6.976	0.395	7.371
Interruptible - Large	5.709	0.904	6.613
Seasonal- Winter	6.976	0.395	7.371
Seasonal- Summer	6.976	0.395	7.371
AFB	5.646	0.132	5.778
Firm Contract	5.709	0	5.709

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RATE RECONCILIATION
RESIDENTIAL GAS SERVICE - RATE 60
Pro Forma 2004

	Billing Units		Current Rate	Current Amount	Proposed Rate	Proposed Amount	Change
Residential Rate 60							
Basic Service Charge	37,933	Cust	$0.25	$3,461,386	$0.26	$3,599,842	$138,456
Distribution Charge	3,280,458	dk	1.435	4,707,457	1.666	5,465,243	757,786
Cost of Gas	3,280,458	dk	6.976	22,884,475	6.976	22,884,475	0
Total Revenue Rate 60				$31,053,318		$31,949,560	$896,242

Total Distribution Revenues Per Design	$9,065,085
Target Distribution Revenues	9,065,916
Difference	($831)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RESIDENTIAL GAS SERVICE - RATE 60
Pro Forma 2004

Current Non-Gas Revenues	$8,168,843
Proposed Revenue Increase	897,073
Total Revenue Requirement	$9,065,916
Less:	
Proposed Base Rate Revenues	3,599,842
Remaining Revenues To Be Collected	5,466,074
Total Rate 60 Consumption	3,280,458
Base Distribution Charge	$1.666

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RATE RECONCILIATION
FIRM GENERAL GAS SERVICE - RATE 70
Pro Forma 2004

	Billing Units		Current Rate	Current Amount	Proposed Rate	Proposed Amount	Change
Firm General Rate 70							
Basic Service Chg Rate 700	3,708	Cust	$0.33	$446,630	$0.35	$473,697	$27,067
Basic Service Chg Rate 701	1,384	Cust	0.66	333,406	0.70	353,612	20,206
Subtotal	5,092			$780,036		$827,309	47,273
Distribution Delivery	2,239,643	Dk	1.078	2,414,335	1.226	2,745,802	331,467
Cost of Gas	2,239,643	Dk	6.976	15,623,750	6.976	15,623,750	0
Total Revenue				$18,818,121		$19,196,861	$378,740

Total Distribution Revenues Per Design	$3,573,111
Target Distribution Revenues	3,573,287
Difference	($176)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
FIRM GENERAL GAS SERVICE - RATE 70
Pro Forma 2004

Current Non-Gas Revenues	$3,194,371
Proposed Revenue Increase	378,916
Total Revenue Requirement	$3,573,287
Less:	
Base Rate Revenues	827,309
Remaining Revenues To Be Collected	2,745,978
Total Rate 70	2,239,643
Base Commodity Charge	$1.226

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
LARGE INTERRUPTIBLE SERVICE - RATES 82 & 85
Pro Forma 2004

CLASS	Billing Units	Current Rate	Current Amount	Proposed Rate	Proposed Amount	Change
Basic Service Charge						
Rate 85 Sales	12 Bills	$150.00	$1,800	$175.00	$2,100	$300
Rate 82 Transport	96 Bills	200.00	19,200	225.00	21,600	2,400
Subtotal			21,000		23,700	$2,700
Distribution Delivery						
Rate 85 Sales	87,788 dk	0.177	$15,538	0.183	$16,065	527
Rate 82 Transport	534,690 dk	0.177	94,640	0.183	97,848	3,208
Cost of Gas	87,788 dk	5.709	501,182	5.709	501,182	0
Total Revenue			$632,360		$638,795	6,435

Total Rate 82 & 85 Distribution Revenue	$137,613
Target Distribution Revenue	137,322
Difference	$291

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
PROPOSED RATE DESIGN
LARGE INTERRUPTIBLE SERVICE - RATES 82 & 85
Pro Forma 2004

Revenue Requirement	$131,178
Less: Flexed Contracts	0
Proposed Revenue Increase	6,144
Total Revenue Requirement	$137,322
Less: Base Service Charge Revenues	23,700
Total Revenue Requirement	$113,622
Total Throughput Rates 82 & 85 (Excluding Flexed Contracts)	622,478
Commodity Charge	$0.183

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
REVENUE RECONCILIATION
LARGE INTERRUPTIBLE SERVICE - RATES 82 & 85
Pro Forma 2004

Large Interruptible Sales	
Base Rate Revenues	$2,100
Energy Revenues	16,065
Cost of Gas	501,182
Total Sales Revenues	519,347
Large Interruptible Transportation	
Base Rate Revenues	$21,600
Transportation Revenues - @ Ceiling	97,848
Transportation Revenues - Flexed	0
Total Transportation Revenues	$119,448
Total Large Interruptible Revenues Per Design	$638,795
Total Large Interruptible Target Revenues	638,504
Difference	$291

MONTANA-DAKOTA UTILITIES CO.
PGA TARIFF SHEET
BLACK HILLS
EFFECTIVE JUNE 2004

	Residential & General Service	Optional Seasonal	Large Interruptible	Air Force
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$6.945	$5.820	$5.671	$5.607
Prior Gas Cost	6.308	5.168	5.011	4.955
Current Gas Cost Adjustment	$0.637	$0.652	$0.660	$0.652
Surcharge Adjustment:				
Current Adjustment	0.395	0.395	0.904	0.132
Prior Adjustment	0.395	0.395	0.904	0.132
Change in Surcharge Adjustment	$0.000	$0.000	$0.000	$0.000
Net Increase (Decrease) in Gas Costs	**$0.637**	**$0.652**	**$0.660**	**$0.652**
Gas Cost Level	$6.945	$5.820	$5.671	$5.607
Plus: Surcharge	0.395	0.395	0.904	0.132
Total Gas Cost Level in Tariff Rates	$7.340	$6.215	$6.575	$5.739

MONTANA-DAKOTA UTILITIES CO.
DESCRIPTION OF UTILITY OPERATIONS

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (Montana-Dakota) is an operating public utility engaged in the distribution and sale of natural gas and propane and the production, transmission, distribution and sale of electricity in North Dakota, eastern Montana, northern and western South Dakota and northern Wyoming.

Montana-Dakota has a four-state natural gas system serving markets in North Dakota, including Bismarck, Dickinson, Jamestown, Minot and Williston; eastern Montana, including Billings, Glendive, Miles City and Wolf Point; western and central South Dakota, including Rapid City and Pierre; and several communities in northern Wyoming, including Sheridan. Montana-Dakota operates a propane vaporization distribution system in Hettinger, North Dakota. It also has an interconnected electric system serving markets in North Dakota, including Bismarck, Dickinson and Williston; eastern Montana, including Glendive, Miles City and Wolf Point; and northern South Dakota. The Company also has a separate electric system serving Sheridan, Wyoming and areas adjacent thereto. As of December 31, 2003, the Company supplied natural gas at retail to approximately 220,800 customers located in 144 communities and adjacent rural areas. As of the same date, Montana-Dakota supplied electricity to approximately 117,400 customers located in 180 communities and adjacent

rural areas. Montana-Dakota has obtained and holds valid and subsisting franchises authorizing it to carry on the utility business in all of the municipalities in which it is engaged where such franchises are required. Montana-Dakota's service area has historically been primarily agricultural, including a number of irrigated areas. The important industries among the Company's customers are oil refining, sugar refining, cement and bentonite manufacturing, coal mining, gold mining and clay products manufacturing. There has been a significant increase in oil and natural gas exploration and development and lignite coal mining in the Company's service territory.

Please refer to FERC Form 1, Annual Report for Electric Utilities, pages 402-403, 410-411, and 422-425 for the electric generating stations and miles of line.

The last general gas rate case was filed on December 30, 2002 with the South Dakota Public Utilities Commission in Docket No. NG02-011. The application requested an annual increase in revenues of $2,173,380 or an overall increase of 5.8 percent. The Commission issued an Order dated December 17, 2003 approving a Settlement Stipulation authorizing an increase of $1,306,000 or a 4.14 percent increase.

MONTANA-DAKOTA UTILITIES CO.
INTERCOMPANY TRANSACTIONS
TOTAL COMPANY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003

Please see Rule 20:10:13:84, Statement H, Schedule H-4.

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG04-____
TESTIMONY & 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 South Dakota

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

Before the Public Utilities Commission of South Dakota

Docket No. NG04-___

Direct Testimony
of
Bruce T. Imsdahl

Q. Please state your name and business address.

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

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

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

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

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

Q. Please outline your educational and professional background.

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

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

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

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of our South Dakota natural gas operations, explain our request for a gas rate increase and discuss the policies and reasons underlying the major aspects of the request. I will also identify the Company witnesses in this proceeding. I should note at the outset that this requested increase is applicable only to our Black Hills system customers. This request does not affect natural gas customers served from our East River system.

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

A. The South Dakota natural gas distribution system serves approximately 43,100 customers in 24 communities. The customer mix is about 88.1% residential, 11.8% firm commercial, with the firm contract service, Air Force, small interruptible and large interruptible customers making up about 0.1% of customers. The residential, firm commercial and small interruptible customers use natural gas primarily for space and water heating. As such, Montana-Dakota's system has a low load factor with peak gas requirements occurring during the winter with summer loads being small by comparison. The total annual gas used by our South Dakota customers is 7.8 Mmdk as identified for the test period in this case. Consumption by customer class is as follows: 42.3% residential, 28.9%

firm commercial, 8.2% firm contract service, 7.4% Air Force, 5.2% small interruptible, and 8.0% large interruptible. Montana-Dakota's South Dakota gas service area is a single operating region with a regional office located in Rapid City, a district office located in Spearfish and District Representatives stationed in three other communities in the area. As of December 31, 2003, the Company had 114 full and part time employees who live and work throughout our South Dakota electric and gas service area.

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

A. Yes, I did.

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

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

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

A. Yes. The costs of providing natural gas service can be best broken down into two major categories; first, the cost of gas delivered to the town

border station, where it leaves the interstate or intrastate pipeline and enters our distribution system, and second, the cost of delivering the gas from the town border station through our distribution system to the individual customers. We call this portion distribution costs or non-gas costs.

Natural gas purchased from a producer or supplier is a commodity like wheat or corn and prices are not regulated. The charges for moving the gas to our distribution system on the pipeline system are regulated by the Federal Energy Regulatory Commission or other regulatory agencies. These two elements, which we call "gas costs", are passed on to our customers on a dollar-for-dollar basis as specified in the Purchased Gas Cost Adjustment tariff, and there is no profit made by Montana-Dakota. This portion comprises about 74% of a typical residential bill for gas service.

The distribution cost portion of our rates is regulated by this Commission and is the subject of this proceeding. This portion includes operation and maintenance expenses, depreciation, taxes, and a component for the opportunity to earn a return on the investment we have in facilities to provide natural gas service. The distribution costs are about 26% of a typical residential bill.

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting an increase of $1,281,417 based on a 2003 test year adjusted for known and measurable changes.

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

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

Class	Change
Residential	2.9%
Firm General Service	2.0%
Firm Contract Service	0.0%
Air Force	0.0%
Small Interruptible	0.0%
Large Interruptible	1.0%
Total	2.2%

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

A. The primary reason is increased operating expenses driven largely by increases in labor, benefit costs and depreciation expense.

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

A. Montana-Dakota's gas rates were last increased in December 2003. The increase was $1,305,612 annually and was authorized in Docket No. NG02-011.

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

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

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

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

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

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

A. Yes. In my opinion, the proposed rates are just and reasonable because they are reflective of the total costs being incurred by Montana-Dakota in providing gas service to its customers. The proposed rates will allow Montana-Dakota the opportunity to earn a just and reasonable return on its Black Hills area South Dakota gas operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

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

BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. _____

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

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

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

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

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

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

From 1982 to 1986 I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986 I was coordinator for

the Electric Rate Fundamentals course of the Edison Electric Institute. In 1986 I accepted an appointment as assistant professor at Trinity University in San Antonio, Texas, where I taught courses in financial management, investments, corporate finance, and corporate financial theory.

In 1988 I returned to H. Zinder & Associates as a consultant. I have testified or filed testimony or affidavits before the Federal Energy Regulatory Commission on more than twenty occasions. Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, revenue requirements and market power. I also have filed testimony on the cost of capital and capital structure issues for electric, gas distribution and oil and gas pipeline operations before state regulatory bodies in Alaska, New York, North Dakota, Minnesota, Montana, South Dakota, and Wyoming, and the Comision Reguladora de Energia de México ("CRE"). In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing and utility economics before the U.S. Postal Rate Commission, the Alberta Energy and Utilities Board, and state public utility Commissions in Iowa, Maine, Montana, North Dakota, Texas and Wisconsin. During the course of my consulting career, I have conducted many studies on issues related to regulated industries and have served as an advisor to numerous clients on economic, competitive, rate and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute.

I. INTRODUCTION

Scope and Overview

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

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

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

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

Source	Amount (000s)	Percent	Cost	Overall Rate of Return
Long-Term Debt	$154,100.0	45.589%	8.624%	3.932%
Preferred Stock	$16,150.0	4.778%	4.618%	0.221%
Common Equity	$167,772.7	49.633%	11.000%	5.460%
TOTAL	$338,022.7	100.00%		9.613%

As my testimony discusses, an overall allowed rate of return of 9.613 percent, with an 11.00 percent return on common equity, represents the cost of capital for Montana-Dakota.

Company Background

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

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

In 2003, Montana-Dakota and the much smaller Great Plains served a total of 244,000 residential, commercial and industrial gas distribution customers. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's natural gas distribution assets comprised 7.0 percent of MDU Resources' total assets. In addition, the natural gas distribution utility revenues and operating income accounted for 11.5 percent and 1.5 percent of MDU Resources' total, respectively. South Dakota accounted for 19 percent of the natural gas distribution utility operating revenues, while North Dakota (39 percent), Montana (25 percent), Wyoming (6 percent) and Minnesota (11 percent) accounted for the other 81 percent of natural gas distribution utility revenues.

II. FINANCIAL MARKET STUDIES

Criteria for a Fair Rate of Return

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

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

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

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591, 603 (1944)).* There the Court described the relevant criteria as follows:

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

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

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

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

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

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

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

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

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

Q9. How is the cost of common equity determined?

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

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

Cost of Debt

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

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

Q11. What cost of preferred stock did you use?

A. Montana-Dakota's annual cost of preferred stock is 4.618 percent, as shown also in the Prepared Direct Testimony of Craig Keller.

Interest Rates and the Economy

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

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

growth during the past thirty years, with only temporary recessionary periods. Real growth in the Gross Domestic Product ("GDP") has averaged 3.1 percent annually during the past 30 years, 3.4 percent for the past 20 years and 3.4 percent for the past ten years. After growing slowly during 2001 and the first half of 2002, the economy has been growing at above average rates recently. For example, the U.S. GDP grew at an annual rate of 8.2 percent during the third quarter of 2003, a rate of 4.1 percent during the fourth quarter of 2003, and a rate of 4.2 percent during the first quarter of 2004. Stock prices in general have declined somewhat in recent months. During the past three years there has been a marked increase in the perceived risk of common equity investments in general, and also an increase in the perceived risk of energy and utility-related investments in particular.

Investors also are influenced by the level of inflation, which has been persistent in the past. During the past decade, the Consumer Price Index has increased at an average annual rate of 2.5 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 1.9 percent. In the first quarter of 2004, the Consumer Price Index showed a rate of inflation of 3.2 percent; indicating that inflation may be an increasingly important factor in the economy.

Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates provide a standard measure of returns currently available on less risky securities. As Page 2 of Schedule 1 of Exhibit No. ___(JSG-2) shows, long-term interest rates have declined by 100 to 200 basis points during the past two years. The recent yields

on A-rated public utility bonds have been approximately 6.3 percent and the yields on Baa-rated public utility bonds have been approximately 6.4 percent.

Discounted Cash Flow ("DCF") Method

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

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

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

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

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

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

where:

K = the cost of capital, or total return that investors expect to receive;

P = the current market price of the stock;

D = the current annual dividend rate; and

g = the future annual growth rate that investors expect.

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

Flotation Cost Adjustment

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?

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. Schedule 3 of Exhibit No. ___(JSG-2) shows a representative sample of flotation costs incurred with 34 new common stock issues by natural gas transmission and distribution companies between 1992 and 2002. Flotation costs associated with these new issues averaged 4.77 percent. This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Montana-Dakota must have an expected return that places a value on its equity that is approximately 4.75 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.0475.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to enable a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic

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

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

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

DCF Study of Natural Gas Distribution Companies

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

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

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

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

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

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

A. These calculations are shown on page 3 of Schedule 2 of Exhibit No. __(JSG-2). For the price component of the calculation I used the average of the high and low stock prices experienced by each company during the six month period from November 2003 to April 2004. The dividend yields were calculated for each

company by dividing the indicated annual dividend by the average of the stock prices for each company. These dividend yields can be multiplied by the quarterly DCF model factor (1 + .625 g) to arrive at the dividend yield component of the DCF model.

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

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

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

Second-Stage Retention Growth Analysis

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

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

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

A. Among the best sources of information regarding investors' growth rate expectations are the long-term earnings growth rate forecasts of investment analysts. Zack's is a service that collects estimates by professional investment analysts and publishes a summary of the consensus forecasts. I have used the Zack's consensus forecasts as the source for analysts' forecasts in my calculations. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 5, the average of the analysts' long-term growth rate estimates for the natural gas distribution proxy companies is 5.1 percent.

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

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

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

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

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

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

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

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

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

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

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have 3-5 years in the future. Since these retention rates are projected for several years in the future they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect 3-5 years in the future generally represent a minimum "cruising speed" that companies can be expected to maintain indefinitely. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies is shown on page 4 of Schedule 2 of Exhibit No.___(JSG-2). The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that are being retained and reinvested in the company. This earnings retention rate is multiplied times the projected return on common equity to arrive at the projected retention growth rate. The average retention growth rate for the proxy companies is 5.5 percent.

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

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

proxy companies. In these calculations, I gave a two-thirds weighting to the analysts' growth rate projections to reflect the fact that analysts are attempting to evaluate all sources of growth and not just growth that is expected to result from retained earnings. This weighting also reflects the fact that the analysts' long-term growth forecasts can be expected to prevail for a relatively long period of time in the future. This two-thirds weighting for analysts' forecasts is the same weighting that the FERC used in Opinion No. 414-A for setting the allowed return on equity for natural gas pipeline companies. *Transcontinental Gas Pipeline Co.*, 80 FERC ¶ 61,084 (1998). The average of the weighted average growth rates for the proxy companies is 5.2 percent and the median is 4.9 percent.

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

A. The dividend yield for each company shown on page 3 of Schedule 2 of Exhibit No.___(JSG-2) is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.0475 to arrive at the cost of common equity capital for the proxy companies. These calculations are shown on page 6 of Schedule 2 of Exhibit No.___(JSG-2). This Second-Stage Retention Growth DCF analysis indicates that the cost of common equity capital for the natural gas distribution proxy companies is in a range between 8.9 percent and 12.0 percent.

The median for the group is 9.8 percent and the average for the group is 10.0 percent.

Basic DCF Analysis

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

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

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

A. These calculations are shown on page 7 of Schedule 2 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.0475, to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a median cost of common equity for the proxy companies of 9.8 percent and an average cost of 9.9 percent.

Primary DCF Analysis

Q30. Would you please describe your Primary DCF analysis?

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

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

A. One important factor will be growth in the overall economy. Page 1 of Schedule 1 of Exhibit No.___(JSG-2) shows that the United States Gross Domestic Product has grown at an average annual rate of 7.1 percent during the past 30 years. During the past decade U.S. GDP growth has averaged 5.2 percent. It is reasonable to expect that long-term future growth in the economy generally will be comparable to past growth rates. For example, DRI-WEFA forecasts that the U.S. GDP will grow at a rate of approximately 5.9 percent over the long-term.

Another factor will be demand for natural gas. Natural gas usage has been increasing in recent years and many analysts are expecting demand to increase steadily during the next decade and beyond. For example, the Energy Information Administration of the U.S. Department of Energy forecasts that gas consumption in the United States will grow from its current level of approximately 23 Tcf per year to approximately 34 Tcf per year in 2020. Steady increases in demand for gas

distribution services of the proxy companies should be fueled by the availability of domestic and imported supplies and the superior environmental characteristics of natural gas that should allow it to achieve a greater market share relative to other fuels. While the real gas distribution capacity of the proxy companies is expected to increase, additional growth will occur because the amount of investment required will increase in nominal dollars. In other words, the effects of inflation needs to be added to the real growth rate in the industry to get a measure of likely growth in investment and earnings.

In my opinion, investors reasonably expect the nine companies in this comparison group to grow at a rate that is somewhere in the range of 4.75 percent to 6.25 percent. Based on the average growth rate of approximately 5.6 percent currently projected by investment analysts, as well as the 5.9 percent growth rate in the economy, increasing demands for natural gas, and my review of these companies, I consider this growth rate range to be a reasonable estimate of the future growth expectations that are implicit in current dividend yields. This growth rate range is also consistent with the retention growth rates projected for these companies and their ability to grow by means other than retained earnings.

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

A. Page 8 of Schedule 2 of Exhibit No. ___(JSG-2) shows the calculation of the cost of capital based on my primary DCF growth rate estimates. The dividend yield used in this analysis is the average dividend yield for the natural gas distribution proxy companies that is developed on page 3 of Schedule 2. This

market-based primary DCF analysis indicates that the cost of capital for the proxy companies is approximately in the range of 9.5 percent to 11.1 percent.

Risk Premium Analyses

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

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

Investors' expectations for the future are influenced to a large extent by their knowledge of past experience. Ibbotson Associates annually publishes

extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual returns on large company common stocks have exceeded the yields on Long-Term U.S. Government Bonds by an average of 640 basis points (6.4 percent). However, the returns on relatively small company stocks in the size range of Montana-Dakota's natural gas distribution operations have been 1,130 basis points (11.3 percent) above the yields on long-term government bonds. As shown on page 1 of Schedule 2 of Exhibit No. ___ (JSG-2), Montana-Dakota is a fraction of the size of any of the proxy companies. In recent months, the yield on long-term U.S. Government bonds has been approximately 5.1 percent. Adding a 6.4 percent premium to a yield of 5.1 percent indicates that investors in large company common stocks expect a return of at least 11.5 percent. Adding the 11.3 percent premium for companies in Montana-Dakota's size range suggests a required return of 16.4 percent.

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

Alternative Equity Investment Analysis

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

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

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

A. The potential returns are often considerably above 20 percent and the average returns for broad-based, diversified portfolios have averaged 20.0 percent or more in recent years. For purposes of comparison with allowed returns for regulated natural gas distribution operations, a better indicator of earnings on alternative equity investments is provided by data on 746 industrial, retail and transportation companies published by *The Value Line Investment Survey*. Excluding extraordinary and non-recurring items, the average returns on the original cost book value of common equity for these companies in recent years has been:

1998	29.12%
1999	30.35
2000	32.17
2001	24.88
2002	26.23
5-year Average	**28.55%**

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

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

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

As a benchmark, allowed returns for natural gas distribution companies can be compared to returns on book value for large companies. Normal returns have averaged 28.6 percent during the past five years. As this comparison indicates, an allowed return of 11.00 percent for Montana-Dakota would be quite low in

comparison with the returns earned by other large companies. Consequently, a return of this magnitude could potentially be too low for Montana-Dakota's natural gas distribution operations to successfully compete for capital.

Relative Risk Analysis

Q37. Have you compared the risks faced by Montana-Dakota's South Dakota natural gas distribution operations with the risks faced by the proxy group of companies?

A. Yes. There are four broad categories of risk that concern investors. These include:

i. Business Risk;
ii. Regulatory Risk;
iii. Financial Risk; and,
iv. Market Risk.

Q38. Would you please describe the business risks inherent in the natural gas distribution industry?

A. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists because forecasts of both demand and costs are inherently uncertain. Markets change and the level of demand for the firm's output may be sufficient to cover its costs at one time and later become insufficient. Sunk investments in long-lived natural gas distribution assets, for which cost recovery occurs over a period of thirty years or more, are subject to enormous uncertainties and risks that demand, costs, supply and competition may change in ways that adversely affect the value of the investment.

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

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

As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's natural gas distribution operations are considerably smaller than the operations of any of the proxy companies and a small fraction of the size of the typical proxy company. For example, Montana-Dakota's natural gas distribution assets are equal to only 7.5 percent of the assets of the median proxy company. Similarly, Montana-Dakota's gas distribution operating revenues and operating income are only 20.9 percent and 2.1 percent of the level for the median proxy company. Thus, depending upon the measure of size, the typical proxy company is somewhere between approximately five and 47 times the size of Montana-Dakota's natural gas distribution operations.

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

Ibbotson Associates has documented the significantly higher returns that generally have been associated with small companies. On a practical level, Montana-Dakota's relatively small natural gas distribution operations are heavily

dependent upon a relatively undiversified local economy. Factors that negatively influence the local economy can reduce demand for Montana-Dakota's gas distribution services and adversely impact investments in facilities used to provide those services.

In addition, the threat of bypass is more significant for a smaller company and the threat is especially great for a company such as Montana-Dakota that is located near a gas production area. Montana-Dakota also faces direct competition from propane and heating oil for new and existing load in its South Dakota service territory. Another risk faced by Montana-Dakota is the fact that it recovers a substantial portion of its fixed costs in the volumetric component of its rates.

Considering only its smaller size, Montana-Dakota might require a return that is more than 100 basis points higher than the return required for the typical proxy company.

Q40. What are the regulatory risks faced by Montana-Dakota's South Dakota utility operations?

A. Regulatory risk is closely related to business risk and might be considered just another aspect of business risk. To the extent that the market demand for a natural gas distribution company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may nevertheless set the rates at a level that will not allow full cost recovery. In effect, the binding constraint on utilities is often posed by regulation rather than by the working of market forces. One purpose of regulation is to provide a substitute for

competition where markets are not workably competitive. As such, regulation often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries. Moreover, there is the perceived risk that regulators may set allowed returns so low as to effectively undermine investor confidence and jeopardize the ability of gas distribution utilities to finance their operations. Thus, in some instances regulation may substitute for competition and in other instances it may limit the potential returns available to successful competitors. In either case, regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the natural gas distribution industry.

In South Dakota, Montana-Dakota's rates are set by using an historical test year with updates for known and measurable changes generally only to the time of intervenor testimony and preparation. Thus, inflation and regulatory lag cause Montana-Dakota's rates to be inadequate by the time they go into effect. This problem of regulatory lag significantly increases Montana-Dakota's risks in South Dakota and is particularly serious because inflation is increasing. Thus, in my opinion, Montana-Dakota's South Dakota natural gas operations should be considered to have above-average regulatory risk relative to the proxy companies at this time.

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

A. Financial risk exists to the extent a company incurs fixed obligations in financing its operations. These fixed obligations increase the level of income which must be generated before common stockholders receive any return and

serve to magnify the effects of business and regulatory risks. Fixed financial obligations also increase the probability of bankruptcy by reducing the company's financial flexibility and ability to respond to adverse circumstances. One possible indicator of investors' perceptions of relative financial risk in this case might be obtained from bond ratings. Page 2 of Schedule 2 of Exhibit No. ___ (JSG-2) shows the bond ratings assigned by Moody's and Standard & Poor's to each of the companies in the comparison group and to MDU Resources bonds that are secured by the assets of Montana-Dakota Utilities Co. The median bond ratings for companies in the proxy group are A for Standard & Poor's and A2 for Mergent. In comparison, MDU Resources bonds carry an A- rating with Standard & Poor's and an A2 rating with Moody's. This suggests that the perceived risk of MDU Resources' bonds is very close to that of the typical company in the comparison group. Examination of the capital structure data shown on page 9 of Exhibit No. ___ (JSG-2), Schedule 2 shows that Montana-Dakota's filed common equity ratio, 49.6 percent, is also close to the median for the proxy group. This common equity ratio, combined with its bond rating, suggests average financial risk for Montana-Dakota's South Dakota natural gas distribution operations.

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

A. Market risk is associated with the changing value of all investments because of business cycles, inflation and fluctuations in the general cost of capital throughout the economy. Different companies are subject to different degrees of market risk largely as a result of differences in their business and financial risks.

Because of the substantial similarity in their operations, Montana-Dakota's degree of market risk is not significantly different from that of the companies in the natural gas distribution comparison group.

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

A. Montana-Dakota faces overall risks that are above average relative to those of the proxy companies. Montana-Dakota has above-average business risks due primarily to its exceptionally small size relative to the proxy companies and its exposure to competition and a relatively undiversified economy. Moreover, the regulatory lag experienced in its South Dakota operations suggests above average risks. However, it has financial risks that are average relative to the proxy companies. These factors lead me to conclude that the overall risks of Montana-Dakota's natural gas distribution operations are above average relative to the risks of the proxy companies.

III. SUMMARY AND CONCLUSIONS

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

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

	Cost of Capital Median/Average	Range
DCF Analyses		
Natural gas distribution Proxies:		
- Second-Stage Retention Growth	9.8%/10.0%	8.9%/12.0%
- Basic DCF	9.8%/9.9%	8.9%/11.3%
- Primary DCF	10.3%	9.5%/11.1%
Benchmark Analyses		
Risk Premium Return Based On:		
- U.S. Treasury Bonds		
v. Large Companies	11.5	
v. Small Companies	16.4	
- Corporate Bonds		
v. Large Companies	12.2	
v. Small Companies	17.1	
Alternative Investments		
- Value Line Industrials	28.6	

My second-stage retention growth analysis indicates a median cost of common equity capital of 9.8 percent and an average cost of 10.0 percent. The range for this analysis is 8.9 percent to 12.0 percent. Because projected retention growth is sustainable indefinitely and it is directly related to the growth rate expectations for an individual company, it is a good indicator of the minimum growth rate that a company can maintain in the very long run. However, companies can achieve growth through means in addition to retained earnings. Consequently, analysts' forecasts provide the best measure of expected growth for the foreseeable future. At this time, the average of the analysts' forecasts and the retention growth forecasts for the proxy companies are identical. Combining

these two measures provides a good estimate of the long-term growth that investors can reasonably expect from these proxy companies.

The Basic DCF analysis, which relies solely on the analysts' forecasts, also provides a good estimate of investors' growth rate expectations and required return for the proxy companies. This DCF analysis indicates a median required rate of return of 9.8 percent and an average rate of return of 9.9 percent. The range of results for this analysis is 8.9 percent to 11.3 percent.

My primary approach has been to analyze a variety of sources of information, including investment analysts' forecasts, in order to estimate a weighted average annual growth rate that investors reasonably can expect the natural gas distribution comparison companies to achieve during a long period of time in the future. This primary DCF analysis indicates that the cost of capital for natural gas distribution companies with risks comparable to those of Montana-Dakota is in a range between 9.5 percent and 11.1 percent. The mid-point of this range is approximately 10.3 percent.

My risk premium analyses indicate that my DCF estimates produce a premium over corporate bond yields that is below the average long-run risk premium available from common stocks. The DCF return estimates provide a premium over the return on corporate bonds that is considerably below the average premium experienced by companies in Montana-Dakota's relative size range. In addition, my examination of returns available on alternative equity investments suggests that my DCF estimates are far below the 28.6 percent average normal returns earned by the Value Line Industrials in recent years.

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

A. My analyses indicate that an appropriate allowed rate of return on common equity for Montana-Dakota's South Dakota natural gas distribution operations at this time would be 11.00 percent. This recommended return reflects my assessment that Montana-Dakota's overall risks are above average relative to the proxy group at this time.

Q46. Does this conclude your Prepared Direct Testimony?

A. Yes.

Montana-Dakota Utilities Co.

General Economic Statistics

1973-2003

Year	Percentage Price Changes: Consumer Price Index	Percentage Price Changes: GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP (Billions)
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
2003	2.2%	1.7%	4.8%	10,987.9
Average Rate of Change: 1/				
1973-2003	4.9%	4.2%	3.1%	7.1%
1983-2003	3.1%	2.5%	3.4%	5.8%
1993-2003	2.5%	1.9%	3.4%	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 2004 and *Economic Indicators*, March 2004.

Montana-Dakota Utilities Co.

Mergent Bond Yield Averages
May 2002 - April 2004

		Average Corporate	Public Utility Bonds	
			A-Rated	Baa-Rated
2002	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
2004	JAN	6.08	6.15	6.47
	FEB	6.00	6.15	6.28
	MAR	5.84	5.97	6.12
	APR	6.22	6.35	6.46

Source: Mergent Bond Record.

Montana-Dakota Utilities Co.

Moody's Natural Gas Distribution Companies
Fiscal Year 2003 Operating Data

	Assets ($000,000)	Operating Revenues ($000,000)	Operating Income ($000,000)	
AGL Resources, Inc.	$3,978	$984	$242	
Atmos Energy Corp.	$2,519	$2,800	$188	1/
Energen Corporation	$1,781	$842	$220	
KeySpan Corp.	$14,626	$6,915	$1,007	
NICOR, Inc.	$3,797	$2,663	$171	
Northwest Natural Gas Co.	$1,591	$611	$102	
Piedmont Natural Gas Co., Inc.	$2,296	$1,221	$143	2/
South Jersey Industries, Inc.	$1,126	$697	$78	
WGL Resources, Inc.	$2,436	$2,064	$228	1/
High	$14,626	$6,915	$1,007	
Median	**$2,436**	**$1,221**	**$188**	
Low	$1,126	$611	$78	
Montana-Dakota Gas Distribution	**$183**	**$255**	**$4**	
MDU Resources Group, Inc.	$2,623	$2,224	$273	
Montana-Dakota Gas Distribution % of:				
- Proxy Company Median	**7.5%**	**20.9%**	**2.1%**	
- MDU Resources Group, Inc.	7.0%	11.5%	1.5%	

*Also includes Results for Great Plains Natural Gas Co.

Data as of 12/31/03 unless otherwise noted.
1/ Data as of 09/30/03.
2/ 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	Mergent
AGL Resources, Inc.	A-	A3
Atmos Energy Corp.	A-	A3
Energen Corporation	A-	A1
KeySpan Corp.	A+	A2
NICOR, Inc.	AA	Aa3
Northwest Natural Gas Co.	A	A2
Piedmont Natural Gas Co., Inc.	A	A3
South Jersey Industries, Inc.	A	Baa1
WGL Resources, Inc.	AA-	A2
Median	A	A2
MDU Resources	A-	A2

Source: C.A. Turner, *Utility Reports*, May 2004.

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Dividend Yields
November 2003 - April 2004

	Stock Price November '03 - April '04				
	High	Low	Average	Dividend	Yield
AGL Resources, Inc.	$ 30.63	$ 27.50	$ 29.07	$ 1.16	3.99%
Atmos Energy Corp.	$ 27.00	$ 23.92	$ 25.46	$ 1.22	4.79%
Energen Corporation	$ 44.72	$ 36.62	$ 40.67	$ 0.74	1.82%
KeySpan Corp.	$ 38.99	$ 33.64	$ 36.32	$ 1.78	4.90%
NICOR, Inc.	$ 37.43	$ 32.03	$ 34.73	$ 1.86	5.36%
Northwest Natural Gas Co.	$ 33.00	$ 28.91	$ 30.96	$ 1.30	4.20%
Piedmont Natural Gas Co., Inc.	$ 43.95	$ 39.41	$ 41.68	$ 1.72	4.13%
South Jersey Industries, Inc.	$ 42.30	$ 37.85	$ 40.08	$ 1.62	4.04%
WGL Resources, Inc.	$ 30.39	$ 26.20	$ 28.30	$ 1.30	4.59%
Average					4.20%

Sources: America Online, May 10, 2004 and The Wall Street Journal, May 3, 2004.

Montana-Dakota Utilities Co.

Projected Earnings Retention Growth Rates for Selected Natural Gas Distribution Companies

	Value Line Forecast 2006-2008				
	EPS	DPS	ROE	Retention Rate	Retention Growth
AGL Resources, Inc.	2.35	1.12	12.00%	52.34%	6.28%
Atmos Energy Corp.	2.05	1.35	9.50%	34.15%	3.24%
Energen Corporation	3.85	0.83	18.00%	78.44%	14.12%
KeySpan Corp.	3.40	1.90	12.00%	44.12%	5.29%
NICOR, Inc.	2.70	2.00	14.50%	25.93%	3.76%
Northwest Natural Gas Co.	2.40	1.45	10.50%	39.58%	4.16%
Piedmont Natural Gas Co., Inc.	3.05	1.90	11.50%	37.70%	4.34%
South Jersey Industries, Inc.	3.40	1.77	10.50%	47.94%	5.03%
WGL Resources, Inc.	2.15	1.34	9.50%	37.67%	3.58%
Average					5.53%

Source: *Value Line*, Mar. 19, 2004.

Montana-Dakota Utilities Co.

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

		2/3 Zacks 5-Yr Earnings Growth Est.	1/3 Retention Growth	Weighted Average
AGL Resources, Inc.	ATG	5.40%	6.28%	5.69%
Atmos Energy Corp.	ATO	5.80%	3.24%	4.95%
Energen Corporation	EGN	7.20%	14.12%	9.51%
KeySpan Corp.	KSE	5.60%	5.29%	5.50%
NICOR, Inc.	GAS	3.90%	3.76%	3.85%
Northwest Natural Gas Co.	NWN	4.20%	4.16%	4.19%
Piedmont Natural Gas Co., Inc.	PNY	5.20%	4.34%	4.91%
South Jersey Industries, Inc.	SJI	4.50%	5.03%	4.68%
WGL Resources, Inc.	WGL	3.90%	3.58%	3.79%
Average		5.08%	5.53%	5.23%

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.	3.99%	4.13%	5.69%	9.83%	1.0475	10.29%
Atmos Energy Corp.	4.79%	4.94%	4.95%	9.89%	1.0475	10.36%
Energen Corporation	1.82%	1.93%	9.51%	11.43%	1.0475	11.98%
KeySpan Corp.	4.90%	5.07%	5.50%	10.57%	1.0475	11.07%
NICOR, Inc.	5.36%	5.48%	3.85%	9.34%	1.0475	9.78%
Northwest Natural Gas Co.	4.20%	4.31%	4.19%	8.49%	1.0475	8.90%
Piedmont Natural Gas Co., Inc.	4.13%	4.25%	4.91%	9.17%	1.0475	9.60%
South Jersey Industries, Inc.	4.04%	4.16%	4.68%	8.84%	1.0475	9.26%
WGL Resources, Inc.	4.59%	4.70%	3.79%	8.50%	1.0475	8.90%
Average						**10.02%**
High				11.43%		11.98%
Median				9.34%		**9.78%**
Low				8.49%		8.90%

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.	3.99%	4.13%	5.40%	9.53%	1.0475	9.98%
Atmos Energy Corp.	4.79%	4.97%	5.80%	10.77%	1.0475	11.28%
Energen Corporation	1.82%	1.90%	7.20%	9.10%	1.0475	9.53%
KeySpan Corp.	4.90%	5.07%	5.60%	10.67%	1.0475	11.18%
NICOR, Inc.	5.36%	5.49%	3.90%	9.39%	1.0475	9.83%
Northwest Natural Gas Co.	4.20%	4.31%	4.20%	8.51%	1.0475	8.91%
Piedmont Natural Gas Co., Inc.	4.13%	4.26%	5.20%	9.46%	1.0475	9.91%
South Jersey Industries, Inc.	4.04%	4.16%	4.50%	8.66%	1.0475	9.07%
WGL Resources, Inc.	4.59%	4.71%	3.90%	8.61%	1.0475	9.02%
Average						**9.86%**
High				10.77%		11.28%
Median				9.39%		**9.83%**
Low				8.51%		8.91%

Montana-Dakota Utilities Co.

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

Growth Rate Estimate (g)	4.75%	6.25%
Current Dividend Yield (D/P)	4.20%	4.20%
Quarterly Model Dividend Yield Factor (1 + .625 g)	X 1.030	X 1.039
DCF Dividend Yield Component (Y)	4.33%	4.37%
Investor Required Return (Y + g)	9.08%	10.62%
Flotation Cost Adjustment	X 1.0475	X 1.0475
Cost of Capital	9.51%	11.12%
Mid-Point	**10.32%**	

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Capital Structures as of December 31, 2003

	Long-Term Debt (Millions)	%	Preferred Stock (Millions)	%	Common Equity (Millions)	%	Total Capital
AGL Resources, Inc.	$ 807.8	40.83%	$ 225.3	11.39%	$ 945.3	47.78%	$ 1,978.4
Atmos Energy Corp.	$ 873.3	50.45%	$ -	0.00%	$ 857.5	49.55%	$ 1,730.8
Energen Corporation	$ 562.8	44.60%	$ -	0.00%	$ 699.0	55.40%	$ 1,261.9
KeySpan Corp.	$ 5,612.9	56.88%	$ 83.6	0.85%	$ 4,171.5	42.27%	$ 9,868.0
NICOR, Inc.	$ 495.1	39.56%	$ 1.8	0.14%	$ 754.6	60.30%	$ 1,251.5
Northwest Natural Gas Co.	$ 500.3	49.70%	$ -	0.00%	$ 506.3	50.30%	$ 1,006.6
Piedmont Natural Gas Co., Inc.*	$ 462.0	42.30%	$ -	0.00%	$ 630.2	57.70%	$ 1,092.2
South Jersey Industries, Inc.	$ 314.1	51.17%	$ 1.7	0.28%	$ 298.0	48.55%	$ 613.7
WGL Holdings, Inc.	$ 648.8	43.39%	$ -	0.00%	$ 846.4	56.61%	$ 1,495.2
Median		**44.60%**		**0.00%**		**50.30%**	

Sources: Zacks.com.
*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 Utilities Commission of South Dakota

Docket No. NG04-__

Direct Testimony
of
Craig A. Keller, CPA

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

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

Q. Would you please describe your duties?

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

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

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

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

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

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

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

A. Yes, I am.

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

A. I am responsible for presenting Statement A, Statement B, Statement C and Statement G.

Q. Would you describe Statement A, Statement B, Statement C and Statement G?

A. Statement A, pages 1 through 4 show Montana-Dakota's balance sheet as of December 31, 2002 and 2003 as well as March 31, 2003 and 2004. Statement B consists of Montana-Dakota's income statement for the twelve months ended December 31, 2003 and March 31, 2004. Statement C reports Montana-Dakota's retained earnings statement as of December 31, 2003. These statements have been prepared from the Company's books and records that are maintained in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of

Accounts.

Statement G shows the utility capital structure of Montana-Dakota as of December 31, 2003 and the projected average capital structure for 2004. Statement G also includes the associated costs of debt, preferred stock and common equity. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 9.613%. The basis for the requested 11.00% return on common equity contained within the overall requested rate of return is supported by the testimony of Dr. J. Stephen Gaske.

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

A. Yes, they were.

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

A. Yes, they are.

Q. Would you please explain Rule 20:10:13:72, Statement G?

A. Pages 1 and 2 of Rule 20:10:13:72, Statement G summarizes the actual average gas utility capital structure at December 31, 2003 and the projected average capital structure and the related utility costs of capital for 2004. As shown on page 2, the components of the 2004 projected overall annual rate of return, which are used by Ms. Mulkern to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	3.932%
Preferred Stock	0.221%
Common Equity	5.460%
Required Rate of Return	9.613%

The debt costs reflected on Rule 20:10:13:73 Statement G, pages 1 and 2 represent the actual weighted embedded costs of the long-term debt at December 31, 2003 and that projected to be outstanding at December 31, 2004 and are supported by Rule 20:10:13:73 Statement G, pages 3 through 6. In calculating the debt costs the "Yield-to-Maturity" method (also referred to as the Internal Rate of Return ("IRR") method) is used to determine the total cost for each respective debt issue as presented on Rule 20:10:13:73 Schedule G, pages 3 and 4. The yield-to-maturity calculation of each debt issue outstanding gives consideration to the stated rates of interest being paid on such debt, the timing of the interest payments, related issuance expenses, underwriters' commissions and indenture revision costs, the discount or premium realized upon issuance and the amortization of losses on bond redemption transactions.

Rule 20:10:13:74, Statement G, pages 1 through 3, supports the cost of Montana-Dakota's preferred stock capital, representing the weighted cost of the issues at December 31, 2003 and projected to be

outstanding at December 31, 2004.

Rule 20:10:13:75, Statement G, pages 1 through 4, supports the Company's average utility common equity balance at December 31, 2003, and the projected average balance for 2004.

Q. What does Rule 20:10:13:73, Statement G, pages 1 through 6 support?

A. Page 1 is a summary showing the Company's average long-term debt at December 31, 2003 and average cost of debt. Page 2 shows the projected average long-term debt and costs for 2004. Page 3 shows the cost and the debt balance by issue at December 31, 2003. Page 4 show's the projected December 2004 balance by issue. As previously noted, the cost of debt for 2003 and 2004 is based on the yield to maturity of each debt issue outstanding.

Q. Would you please describe Statement G, Rule 20:10:13:73, pages 5 and 6 and explain the amortization method utilized?

A. Pages 5 and 6 show the detail by issue of the annual amortization of net discounts (losses) on advance purchases of debt that are necessary to meet sinking fund requirements. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues, the same calculation as is used by the Company for accounting purposes.

Q. What does Rule 20:10:13:74, Statement G show?

A. Pages 1 through 3 present the average preferred stock balances at December 31, 2003 and the projected average balances for December

2004. The anticipated weighted average cost of preferred stock is also shown. Page 3 sets forth the various preferred stock issues outstanding at December 31, 2003.

Q. What does Rule 20:10:13:75, Statement G, pages 1 through 4 show?

A. Pages 1 and 2 present the common equity balances at December 31, 2003 and the projected average balances for 2004 including the projected changes in the balance. Pages 3 and 4 depict the monthly issuance of common stock and associated costs from January 1999 through December 2003.

Q. What does Rule 20:10:13:76, Statement G, Schedule G-1, page 1 show?

A. Page 1 indicates that, during the five-year period preceding December 31, 2003, MDU Resources Group, Inc. issued 37.9 million additional shares of common stock in connection with a three-for-two stock split. Also during that period, the number of authorized shares of common stock was increased from 75 million at a par value of $3.33 to 150 million with a par value of $1.00.

Q. Would you please describe Rule 20:10:13:77, Statement G, Schedule G-2?

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

Q. Would you please describe Rule 20:10:13:78, Statement G, Schedule G-3?

A. This schedule shows the reacquisition activity for bonds and a summary of scheduled retirements of preferred stock for the 5 years ended December 31, 2003.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Utilities Commission of South Dakota

Docket No. NG04-__

Direct Testimony
of
Rita A. Mulkern

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

A. Yes. My name is Rita A. Mulkern and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Regulatory Analysis Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

A. Would you please describe your duties as Regulatory Analysis Manager?

A. I am responsible for the preparation of cost of service studies, fuel cost adjustments, purchased gas cost adjustments and gas tracking adjustments in each of the jurisdictions in which Montana-Dakota operates.

Q. Would you please describe your education and professional background?

A. I graduated from North Dakota State University in 1981 with a Bachelor of Arts degree with majors in Economics and Business Administration and a minor in Statistics. I joined Montana-Dakota in July 1981 as a Regulatory Statistician, became Cost of Service Supervisor in 1986 and assumed my current position in 1999.

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

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

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

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

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

A. The purpose of my testimony is to present the per books cost of service for the twelve months ended December 31, 2003, the pro forma cost of service reflecting known and measurable adjustments that will occur by December 2004 and the calculation of the revenue deficiency.

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

A. I am sponsoring Statements D through F, Statements H through M, Statements P through R and Exhibit No.___(RAM-1).

Q. What were the results of South Dakota gas operations for the twelve months ended December 31, 2003?

A. Statement M, pages 1 and 2 show the per books income statement and rate base for total Company and South Dakota gas operations. As shown on page 1, South Dakota gas operations had a return on rate base of 4.180 percent for the twelve months ended December 31, 2003. The details for each line item, i.e. sales revenue, other revenue, etc., are

included in the applicable Statement. Pages 3 through 5 list the pro forma adjustments to operating revenues, expenses and rate base. All adjustments were calculated on either a South Dakota specific basis or on a total Company basis and allocated to South Dakota, as indicated on the statement or schedule detailing each adjustment.

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

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense and rate base to the jurisdictions as part of the regular accounting process on a monthly basis. The allocation methods and procedures are the same as have previously been used in Commission proceedings and are based on the principle of assigning and/or allocating costs to the cost causer.

Q. What criteria were used to determine the pro forma adjustments?

A. The pro forma adjustments to operating revenue, expenses and rate base were based on known and measurable changes occurring by December 31, 2004 and are listed on pages 3 through 5 of Statement M. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable.

Q. What adjustments were made to operating revenues?

A. The adjustments to operating revenues are contained in Statement I. Adjustment No. 1 restates the per books consumption at current rates, using the gas costs effective June 1, 2004 adjusted to reflect an annual

gas cost for 2004, exclusive of the surcharge adjustment, and eliminates the unbilled revenue, increasing revenue by $9,959,291.

Adjustment No. 2 increases revenues by $1,752,580 to reflect the effect of normal weather on sales and transportation volumes.

Adjustment No. 3 is an increase to revenues of $603,717 to reflect the annualization of firm customers to the December 2003 level.

Adjustment No. 4 is an increase of $1,184,248 to reflect, on a net basis, the average increase in residential and firm general service customers occurring by December 31, 2004, and lower interruptible sales and transportation volumes.

Adjustment No. 5 includes the late payment revenue of $47,709.

Q. What adjustments were made to operation and maintenance (O&M) expenses?

A. The adjustments to operation and maintenance expenses are contained in Statement H. Pages 1 and 2 of Statement H, Schedule H-1 summarize the O&M expenses, with the details provided on pages 3 through 19.

Adjustment No. 6, shown on page 3, adjusts the cost of gas to reflect the pro forma dk sales and an annual 2004 gas cost level, which was derived by calculating annual demand charges and commodity cost of gas and applying those costs to the June 2004 billing determinants. The distribution loss factor of 1.12 percent represents the current loss factor.

Adjustment No. 7, relating to labor expense, was developed by applying the percentage increase in total Company labor costs to the per

books South Dakota labor expense. The pro forma labor costs were based on 2004 payroll adjusted to reflect a three year average (2002-2004) level of commissions and bonuses.

Adjustment No. 8 to benefits shows an increase of $546,843. Benefits expense consists of medical/dental insurance, pension expense, the Supplemental Income Security Plan (SISP), 401K, post-retirement, workers compensation and other benefits. Each of these items, excluding the other benefits, was adjusted individually by using the 2004 budgeted amounts and applying the percentage increase to each type of benefit. Mr. Conley discusses the inclusion of the SISP expense in his testimony.

Adjustment No. 9 reflects insurance expense at current levels for 2004 and is a decrease of $44,184.

Adjustment No. 10 is shown on page 7 and is an increase of $24,685. Contract labor and consulting expense was reviewed by function, with distribution related expenses increasing 15.59 percent and the gas supply, customer accounting, sales and A&G functions decreasing by 11.05 percent in 2004. The increase in contract labor in the distribution function reflects the increase in expense associated with the services performed by outside parties, such as the costs of line locating, parking lot, and building and grounds maintenance, with the decrease in the other functions related to expenses incurred in 2003 that are not projected to recur in 2004.

Adjustment No. 11 is to vehicles and work equipment expense and is calculated based on the pro forma plant and the proposed depreciation

rates in Statement J. The depreciation expense on these items is not charged to depreciation expense but rather is charged to a clearing account where it is then charged to O&M expense as the vehicles or work equipment is used.

Adjustment No. 12 to postage expense is a decrease of $4,692 in 2004 due to higher than normal expenses in 2003.

Adjustment No. 13 reflects a $362 increase in telephone expense. There were some expense items incurred in 2003 that are not projected to occur in 2004, resulting in expense for 2004 that is relatively flat.

Adjustment No. 14 reflects a decrease in Office Supplies of $15,167. There were some expenses in this category in 2003 that are not projected to recur in 2004.

Adjustment No. 15 adjusts Company consumption and is the expense for electric and natural gas consumption in Company buildings. The electric component is projected to remain flat. The natural gas component is expected to increase $6,972 based on the increase in normalized revenues.

Adjustment No. 16 is to uncollectible accounts and is based on the five year average of net write-offs to pro forma sales and transportation revenues, which results in an increase in uncollectible accounts of $69,359.

Adjustment No. 17 reflects an increase in computer rental for the addition of a new server for the Company's geographic information system (GIS).

Adjustment No. 18 reflects the pro forma level of industry dues and is a decrease of $18,359. Statement H, page 15 shows those dues that are directly assigned or allocated to South Dakota.

Advertising is shown on page 16. Pursuant to past Commission policy, general promotional advertising expense has been eliminated.

Q. Would you explain why you are including institutional advertising expenses?

A. Montana-Dakota is seeking to include institutional advertising that we believe benefits customers and serves the public interest. As a corporate citizen, Montana-Dakota needs to be active in the communities that it serves. Montana-Dakota's motto is "In the community to serve" and one of the ways of being a strong community member is to advertise our company and what we do for the communities. Our communities expect nothing less and advertising in the local newspapers, on television, in school yearbooks, programs, etc., is a necessary part of being active in the community. This advertising benefits the community and the customers in that community, thus serving the public interest.

Q. Would you please continue with your explanation of adjustments to operation and maintenance expenses?

A. Adjustment No. 20 to rate case expense reflects the expenses to be incurred in this case plus the unamortized expense from Docket No. NG02-011, amortized over a three-year period. The adjustment is an increase of $154,437.

Adjustment No. 21 shows the South Dakota portion of expenses associated with the cost of performing a depreciation study for the gas and common property, amortized over a five year period and is an increase of $3,050.

The items adjusted individually above represent approximately 90 percent of total South Dakota gas O&M, as shown on page 19. The remaining items, which make up approximately 10 percent of other O&M, are assumed to remain flat.

Q. What adjustments were made to depreciation expense?

A. The adjustment to depreciation expense is contained in Statement J. Adjustment No. 22 restates annual depreciation expense to the average pro forma level of plant in service, with proposed depreciation rates based on a depreciation study performed by AUS Consultants using plant balances as of December 31, 2001. The proposed depreciation rates are included on Statement J, pages 4 through 7.

Q. What adjustments were made to taxes other than income?

A. The adjustments to taxes other than income are contained in Statement L. Adjustment No. 23 restates ad valorem taxes to the pro forma level of plant in service based on the 2003 ratio of ad valorem taxes to plant and is an increase of $25,924.

Adjustment No. 24 to payroll taxes is an increase of $25,346 based on the ratio of payroll taxes to labor expense for 2003 applied to pro forma labor expense.

Adjustment No. 25 restates the South Dakota Gross Receipts Tax to the pro forma level of revenue and is an increase of $40,315.

Q. What adjustments were made to income taxes?

A. The adjustments to income taxes are contained in Statement K. Adjustment No. 26, shown on page 7, is to interest expense, which is deductible for tax purposes. Interest expense is calculated on the pro forma rate base using the weighted cost of long-term debt and debt ratio from Statement G. The resulting interest expense is a decrease of $60,189 from the per books level.

Adjustment No. 27 calculates the tax depreciation and deferred taxes on the pro forma plant additions and is shown on page 8.

Adjustment No. 28 calculates the current income tax expense on all of the pro forma adjustments to operating revenues and expenses on page 9.

Adjustment No. 29 eliminates the closing/filing and reserve adjustments in the current income tax accrual and in the deferred taxes. This adjustment adjusts current and deferred income taxes to the calculated amount for South Dakota and conforms to past Commission practices.

Q. What adjustments were made to rate base?

A. The pro forma rate base reflects known and measurable adjustments that will occur twelve months beyond 2003. The resulting rate base is stated on an average basis. The pro forma adjustments to rate base are summarized on Statement M, page 5. Adjustment A is the

known and measurable plant additions that will be in service by December 31, 2004. These additions are shown on Statement D, Schedule D-2, pages 3 and 4.

Adjustment B, shown in Statement E, increases the average reserve for depreciation on the per books plant by $1,313,495 to restate the reserve to the average pro forma level in order to match the average pro forma plant levels.

The working capital adjustments are included in Statement F. Adjustment C is a decrease of $5,151 to restate materials and supplies to a thirteen-month average balance.

Adjustment D restates the prepaid insurance expense to a thirteen-month average balance for 2004 and is an increase of $63,192.

Adjustment E reflects the inclusion of the unamortized FAS 106 balance.

Adjustment F, shown on Statement K, page 8, is the increase to deferred taxes to extend the average accumulated deferred tax balance to match the pro forma plant and accumulated reserve.

Adjustment G, shown on Statement K, page 15, is the decrease to deferred taxes to reflect the amortization of the full normalization for 2004.

Adjustment H is the decrease to accumulated investment tax credits (ITCs) to extend the average ITC balances to match the pro forma plant and accumulated reserve.

Adjustment I restates customer advances for construction to eliminate taxes included in the balance and to reflect a thirteen-month

average balance and is a decrease of $17,666 as shown on Statement F, Schedule F-1, page 5.

These are all of the pro forma adjustments to revenue, expense and rate base.

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

A. Exhibit No.____(RAM-1), which is identical to Statement M, pages 6 through 8, shows the calculation of the revenue deficiency of $1,282,133 based on the pro forma operating income and rate base and using the overall rate of return of 9.613 percent from Statement G, page 2.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003
PRO FORMA

	Per Books	Pro Forma Adjustments	Pro Forma
Operating Revenues			
Sales	$44,201,634	$13,538,238	$57,739,872
Transportation	363,186	(38,401)	324,785
Other	216,621	47,709	264,330
Total Revenues	44,781,441	13,547,546	58,328,987
Operating Expenses			
Operation and Maintenance			
Cost of Gas	34,335,947	11,747,188	46,083,135
Other O&M	7,264,809	1,252,379	8,517,188
Total O&M	41,600,756	12,999,567	54,600,323
Depreciation	1,815,584	26,763	1,842,347
Taxes Other Than Income	736,251	91,585	827,836
Current Income Taxes	(1,118,415)	157,441	(960,974)
Deferred Income Taxes	997,246	15,672	1,012,918
Total Expenses	44,031,422	13,291,028	57,322,450
Operating Income	$750,019	$256,518	$1,006,537
Average Rate Base	$17,941,833	$1,178,113	$19,119,946
Rate of Return	4.180%		5.264%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 2003
PRO FORMA

	2003	Pro Forma Adjustments	Pro Forma
Gas Plant in Service	$43,755,476	$2,505,580	$46,261,056
Accumulated Reserve for Depreciation	24,675,602	1,313,495	25,989,097
Net Gas Plant in Service	19,079,874	1,192,085	20,271,959
CWIP in Service Pending Reclassification	324,862		324,862
Total Gas Plant in Service	19,404,736	1,192,085	20,596,821
Additions			
Materials and Supplies	$270,692	($5,151)	$265,541
Prepayments	28,708	63,192	91,900
Unamortized FAS 106	150,699	(15,864)	134,835
Total Additions	450,099	42,177	492,276
Total Before Deductions	$19,854,835	$1,234,262	$21,089,097
Deductions			
Accumulated Deferred Income Taxes	$1,820,405	$87,245	$1,907,650
Accumulated Investment Tax Credits	20,079	(13,430)	6,649
Customer Advances	72,518	(17,666)	54,852
Total Deductions	1,913,002	56,149	1,969,151
Total Rate Base	$17,941,833	$1,178,113	$19,119,946

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - SOUTH DAKOTA

	Before Additional Revenue Requirements	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$57,739,872	**$1,282,133**	$59,022,005
Transportation	324,785		324,785
Other	264,330		264,330
Total Revenues	58,328,987	1,282,133	59,611,120
Operating Expenses			
Operation and Maintenance			
Cost of Gas	46,083,135		46,083,135
Other O&M	8,517,188		8,517,188
Total O&M	54,600,323		54,600,323
Depreciation	1,842,347		1,842,347
Taxes Other Than Income	827,836	1,923 1/	829,759
Current Income Taxes	(960,974)	448,074 1/	(512,900)
Deferred Income Taxes	1,012,918		1,012,918
Total Expenses	57,322,450	449,997	57,772,447
Operating Income	$1,006,537	$831,463	$1,838,000
Rate Base	$19,119,946		$19,119,946
Rate of Return	**5.264%**		**9.613%**

1/ Reflects taxes at 35% after deducting South Dakota Gross Receipts of .15%.

BEFORE THE
PUBLIC UTILITIES COMMISSION OF SOUTH DAKOTA

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

Docket No. NG-04-_____

DIRECT TESTIMONY OF

PAUL W. CONLEY

ON BEHALF OF Montana-Dakota Utilities Co.

DIRECT TESTIMONY OF
PAUL W. CONLEY

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

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

THE SUPPLEMENTAL INCOME SECURITY PLAN

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

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

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

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

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

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

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

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

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

Q. Why are supplemental retirement plans so common?

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

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

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

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

COMPETITIVENESS OF MDU'S EXECUTIVE COMPENSATION PLAN INCLUDING SISP

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

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

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

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

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

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

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

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

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

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

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

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

1) Towers Perrin's 2002 Energy Services Executive Compensation Database, which is conducted in partnership with the Edison Electric Institute (EEI). This source is the most comprehensive survey of executive compensation for the U.S. electric and gas industry, comprising data for 89 investor-owned utilities and public power authorities.
2) Towers Perrin's 2002 Compensation Data Bank General Industry Survey, which is one of the most reputable sources of data on

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

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

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

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

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

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

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

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

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

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

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

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

Q. How does Towers Perrin define competitive compensation?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Does this conclude your testimony?

A. Yes.

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

Before the Public Utilities Commission of South Dakota

Docket No. NG-04-_____

Direct Testimony
of
Tamie A. Aberle

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

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

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

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

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

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

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

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

my present position in May 1999.

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

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

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

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

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

A. I am sponsoring Statement N, Statement O, Exhibit No. ____ (TAA-1) and Exhibit No. ____ (TAA-2). I also sponsor the proposed rate schedules appended to the Application in this proceeding.

Q. Do the proposed changes affect the customers served in the East River service territory?

A. No. The changes proposed in this Docket are applicable only to the customers served by Montana-Dakota in the Black Hills service territory of South Dakota.

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

A. The proposed rates will produce additional revenues of $1,281,417 or 2.2% annually based on the pro forma revenues. Exhibit No. ____ (TAA-1) and Statement O represent a summary by rate classification of

the proposed revenue increase. The exhibit shows the rate number and a description along with the revenues calculated under the present and proposed rates. The amount and percentage increase is also shown for the proposed revenue increase.

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

A. Yes. Turning to Statement N, Schedule N-1, the first report appearing therein is entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the overall requested 9.613% rate of return was to be earned for the demand, energy and customer cost components of each rate schedule.

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

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

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

The class cost of service study is based on the results for South Dakota gas operations recorded for the 12 months ended December 31, 2003 as adjusted to reflect known and measurable changes.

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

A. The results are summarized on Statement N, Schedule N-1, Page 4. The overall South Dakota gas rate of return based on the actual results for the 12 months ending December 31, 2003 adjusted for known and measurable changes is 5.264%. The returns by customer class are as shown below:

Residential Service	4.516%
Firm General Service	5.283%
Firm Contract	29.951%
Air Force	23.397%
Small Interruptible	11.855%
Large Interruptible	7.887%

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

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

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

A. In designing the proposed rates to reflect the additional revenue requirements, I have attempted to group the class rates of return more closely about the overall system return. In order to accomplish this, an increase has been allocated to the Firm General Service and Large

Interruptible classes in an amount necessary for each of these classes to produce the overall rate of return. The remainder of the total increase has been assigned to the Residential class.

Q. What is the percentage of the proposed increase by class of customer?

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

Class	***% Increase***
Residential	2.9%
Firm General Service	2.0%
Firm Contracts Service	0.0%
Air Force	0.0%
Small Interruptible	0.0%
Large Interruptible	1.0%
Overall	2.2%

Q. How are you proposing to collect the allocated increase from the Residential, Firm General Service and Large Interruptible classes?

A. First, I am proposing modest increases to the Basic Service Charges applicable under the firm service rate schedules. The Basic Service Charge under Residential Rate 60 has been set at $0.26 per day which reflects an average monthly charge of $7.90, an increase of $0.30 per month from the currently effective charge. The Basic Service Charge applicable to Firm General Service customers with meters rated less than 500 cubic feet per hour has been set at $0.35 per day and $0.70 per day for customers requiring the larger meters capable of measuring gas flows

of 500 cubic feet per hour or greater. The resulting average monthly charges will be $10.64 and $21.28 respectively representing an increase of $0.61 per month in the Basic Service Charge applicable to customers using meters rated less than 500 cubic feet per hour and an increase of $1.22 per month in the Basic Service Charge for customers requiring meters rated at 500 cubic feet per hour or higher.

The remaining increase in revenues, after taking into account the revenue increase associated with the changes in the Basic Service Charge, will be collected through the applicable Distribution Delivery Charge components. The derivation of the proposed rates is shown in Statement O, Schedule O-1.

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

A. Yes. Exhibit No. ____ (TAA-2) depicts bill comparisons based on typical monthly consumption levels for an annual period for residential and firm general service customers. As shown by the comparisons, the proposed rate structure will result in an average increase of approximately $1.96 per month for the typical Residential customer using 86 dk on an annual basis.

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

A. Yes. Minor changes which are self explanatory have been made to certain of the rate schedules. These changes are clearly denoted on the tariff sheets reflecting the legislative format.

1 Q. Does this conclude your direct testimony?

2 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - SOUTH DAKOTA

Customer Class/Rate	Pro Forma 2004 1/ Customers	Dk	Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	37,933	3,280,458	$31,053,318	$31,949,560	$896,242	2.9%
Firm General Service - Rates 70 & 72	5,092	2,239,643	18,818,121	19,196,861	378,740	2.0%
Firm Contract Service Rate	1	640,689	3,882,454	3,882,454	0	0.0%
Air Force Service - Rate 64	1	573,102	3,272,406	3,272,406	0	0.0%
Small Interruptible						
Sales - Rate 71	7	25,747	195,054			
Transport - Rate 81	30	381,174	210,944			
Total Small Interruptible	37	406,921	405,998	405,998	0	0.0%
Large Interruptible						
Sales - Rate 85	1	87,788	518,520			
Transport - Rate 82	8	534,690	113,840			
	9	622,478	632,360	638,795	6,435	1.0%
Total South Dakota	43,073	7,763,291	$58,064,657	$59,346,074	$1,281,417	2.2%

1/ Rule 20:10:13:85 Statement I, Page 3.

DOCKET NO. _____
EXHIBIT NO. _____ (TAA-1

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

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$139.84	$143.62	$3.78	2.70%
February	11	103.87	106.69	2.82	2.71%
March	11	104.62	107.47	2.85	2.72%
April	7	69.14	71.06	1.92	2.78%
May	4	42.97	44.21	1.24	2.89%
June	3	33.92	34.91	0.99	2.92%
July	2	25.36	26.13	0.77	3.04%
August	2	25.36	26.13	0.77	3.04%
September	3	33.92	34.91	0.99	2.92%
October	6	60.59	62.28	1.69	2.79%
November	9	86.75	89.13	2.38	2.74%
December	13	122.23	125.54	3.31	2.71%
Total	86	$848.57	$872.08	$23.51	2.77%
Average Increase per Month				$1.96	

RATE 60	Current 1/	Proposed 2/
Basic Delivery Charge	$0.25	$0.26
Distribution Delivery	$1.435	$1.666
Cost of Gas	7.371	$7.371

1/ Distribution rates effective with bills rendered on and after December 2, 2003 Docket No.NG02-011 and weighted cost of gas for 2004.
2/ Cost of gas equals weighted cost of gas for 2004.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH 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	25	$221.46	$225.78	$4.32	1.95%
February	19	169.77	173.14	3.37	1.99%
March	19	170.76	174.19	3.43	2.01%
April	12	111.29	113.66	2.37	2.13%
May	8	77.82	79.63	1.81	2.33%
June	5	52.15	53.49	1.34	2.57%
July	3	35.58	36.64	1.06	2.98%
August	3	35.58	36.64	1.06	2.98%
September	6	60.59	62.08	1.49	2.46%
October	10	94.72	96.82	2.10	2.22%
November	16	145.08	148.05	2.97	2.05%
December	22	196.11	199.98	3.87	1.97%
Total	148	$1,370.91	$1,400.10	$29.19	2.13%

RATE 70	Current 1/	Proposed 2/
Basic Delivery Charge	$0.33	$0.35
Distribution Delivery	$1.078	$1.226
Cost of Gas	7.371	$7.371

1/ Distribution rates effective with bills rendered on and after December 2, 2003 Docket No.NG02-011 and weighted cost of gas for 2004.
2/ Cost of gas equals weighted cost of gas for 2004.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH 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	207	$1,769.40	$1,801.28	$31.88	1.80%
February	158	1,353.42	1,377.93	24.51	1.81%
March	158	1,355.40	1,380.03	24.63	1.82%
April	98	847.80	863.51	15.71	1.85%
May	61	535.85	546.12	10.27	1.92%
June	37	332.41	339.09	6.68	2.01%
July	24	223.24	228.03	4.79	2.15%
August	24	223.24	228.03	4.79	2.15%
September	49	433.80	442.25	8.45	1.95%
October	85	738.63	752.45	13.82	1.87%
November	134	1,151.97	1,173.00	21.03	1.83%
December	183	1,566.63	1,594.95	28.32	1.81%
Total	1,218	$10,531.79	$10,726.67	$194.88	1.85%

RATE 70	Current 1/	Proposed 2/
Basic Delivery Charge	$0.66	$0.70
Distribution Delivery	$1.078	$1.226
Cost of Gas	7.371	$7.371

1/ Distribution rates effective with bills rendered on and after December 2, 2003 Docket No.NG02-011 and weighted cost of gas for 2004.
2/ Cost of gas equals weighted cost of gas for 2004.

South Dakota Public Utilities Commission
WEEKLY FILINGS
For the Period of June 3, 2004 through June 9, 2004

If you need a complete copy of a filing faxed, overnight expressed, or mailed to you, please contact Delaine Kolbo within five business days of this report. Phone: 605-773-3201

ELECTRIC

EL04-022 In the Matter of the Joint Request for an Electric Service Rights Exception between Otter Tail Power Company and H-D Electric Cooperative, Inc.

On June 4, 2004, Otter Tail Power Company and H-D Electric Cooperative, Inc. filed a joint request to the Public Utilities Commission for approval of an Electric Service Rights Exception. The exception would allow for H-D Electric to provide electrical service to an irrigation pivot owned by Jonathan Wollman, located in Otter Tail Power Company's service territory in Section 35, Township 115, Range 52 of Hamlin County.

Staff Analyst: Michele Farris
Staff Attorney: Karen Cremer
Date Filed: 06/04/04
Intervention Deadline: 06/18/04

NATURAL GAS

NG04-004 In the Matter of the Filing by Montana-Dakota Utilities Co. for Authority to Increase Rates for Natural Gas Service.

Application by Montana-Dakota Utilities Co. for approval to increase rates for natural gas service in its Black Hills service territory by $1,281,417 or 2.2% based on an adjusted test year ended 12/31/2003. The company states the proposed increase for a residential customer would average about $1.96 per month. The proposed rates may potentially affect 43,100 customers in the Black Hills area of South Dakota.

Staff Analyst: Dave Jacobson
Staff Attorney: Karen Cremer
Date Filed: 06/07/04
Intervention Deadline: 07/09/04

TELECOMMUNICATIONS

TC04-099 In the Matter of the Application of Public Communications Services, Inc. for a Certificate of Authority to Provide Interexchange Telecommunications Services in South Dakota.

Public Communications Services, Inc. is seeking a Certificate of Authority to provide interexchange telecommunications services in South Dakota. The Applicant intends to offer collect, prepaid and debit basis interexchange telecommunications services to inmates of prisons, jails and other confinement institutions.

Staff Analyst: Keith Senger
Staff Attorney: Karen Cremer

Date Docketed: 06/03/04
Intervention Deadline: 06/25/04

TC04-100 In the Matter of the Filing for Approval of a Statement of Generally Available Terms and Conditions for Interconnection, Unbundled Network Elements, Ancillary Services and Resale of Telecommunications Services between Qwest Corporation and 1-800-Reconex, Inc. d/b/a USTel (Fourth Revision)

On June 8, 2004, the Commission received a filing for approval of a Statement of Generally Available Terms and Conditions for Interconnection, Unbundled Network Elements, Ancillary Services, and Resale of Telecommunication Services Provided by Qwest Corporation in the State of South Dakota, Fourth Revision, between Qwest Corporation and 1-800-Reconex, Inc. d/b/a USTel. According to the parties, the Agreement "is a negotiated agreement which sets forth the terms, conditions and prices under which Qwest will provide services for resale to Reconex for the provision of local exchange services." Any party wishing to comment on the Agreement may do so by filing written comments with the Commission and the parties to the Agreement no later than June 28, 2004. Parties to the Agreement may file written responses to the comments no later than twenty days after the service of the initial comments.

Staff Attorney: Rolayne Ailts Wiest
Date Filed: 06/08/04
Initial Comments Due: 06/28/04

TC04-101 In the Matter of the Filing by Granite Telecommunications, LLC for an Amended Certificate of Authority to Provide Interexchange Telecommunications Services and Local Exchange Services in South Dakota.

In an Order dated December 17, 2003, the Commission granted Granite Telecommunications, LLC (Granite) authority to provide local exchange and interexchange telecommunications services in South Dakota, subject to restrictions from offering prepaid services or from accepting customer deposits and advance payments. On June 8, 2004, the Commission received a filing from Granite requesting relief from those restrictions.

Staff Analyst: Keith Senger
Staff Attorney: Karen Cremer
Date Docketed: 06/8/04
Intervention Deadline: 06/25/04

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	)))))	ORDER OF ASSESSMENT OF FILING FEE AND SUSPENSION OF IMPOSITION OF TARIFF NG04-004

On June 7, 2004, Montana-Dakota Utilities Co. (MDU), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in its Black Hills service territory. The application seeks an increase in rates in the approximate amount of $1,281,417 or approximately 2.2%.

SDCL 49-1A-8 authorizes the Commission to require a deposit of up to one hundred thousand dollars ($100,000) in the South Dakota Public Utilities Commission's (SDPUC) regulatory assessment fee fund to defray Commission expenses incident to analyzing and ruling upon this type of filing. The Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26, 49-1A, 49-34A and ARSD 20:10:01:15.02 and 20:10:01:15.03.

At its regularly scheduled meeting of June 22, 2004, the Commission considered this matter. The Commission found that pursuant to SDCL 49-1A-8, MDU shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. Further, an intervention deadline of July 9, 2004, has been established. Pursuant to SDCL 49-31-14, the Commission suspended the operation of the schedule of rates proposed by MDU for 90 days beyond June 7, 2004. It is therefore

ORDERED, that MDU shall deposit a filing fee, to be established by the executive director, in the SDPUC regulatory assessment fee fund and shall deposit any additional amounts as requested by the executive director, not to exceed the statutory limit; it is further

ORDERED, that the proposed schedule of rates shall be suspended for 90 days beyond June 7, 2004, pursuant to SDCL 49-34A-14; and it is further

ORDERED, that the deadline for filing petitions to intervene in this case is July 9, 2004.

Dated at Pierre, South Dakota, this 30th day of June, 2004.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 7/1/04

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

Robert K. Sahr

ROBERT K. SAHR, Chairman

Gary Hanson

GARY HANSON, Commissioner

James A. Burg

JAMES A. BURG, Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	ORDER CORRECTING DATE OF SUSPENSION OF IMPOSITION OF TARIFF NG04-004

On June 7, 2004, Montana-Dakota Utilities Co. (MDU), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in its Black Hills service territory. The application seeks an increase in rates in the approximate amount of $1,281,417 or approximately 2.2%. On June 22, 2004, the Commission suspended the proposed schedule of rates for 90 days beyond June 7, 2004. On July 15, 2004, the Commission Staff advised the Commission that the suspension should have been for 90 days beyond July 7, 2004.

The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-18, 1-26-19, 49-34A-2, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-8.1, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-16, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-20, 49-34A-21, 49-34A-22, and 49-34A-23.

At its July 20, 2004, meeting, the Commission reconsidered this matter. The Commission voted unanimously to change the suspension date from 90 days beyond June 7, 2004, to 90 days beyond July 7, 2004. It is therefore

ORDERED, that the proposed schedule of rates shall be suspended for 90 days beyond July 7, 2004, pursuant to SDCL 49-34A-14.

Dated at Pierre, South Dakota, this 22th day of July, 2004.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 7/28/04

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

Robert K. Sahr

ROBERT K. SAHR, Chairman dk

Gary Hanson

GARY HANSON, Commissioner

James A. Burg

JAMES A. BURG, Commissioner

NG04-004

Chesapeake Regulatory Consultants, Inc.

6837 Guilford Road
Clarksville, MD 21029-1632

Phone: 443.535.0300 Fax: 443.535.0301
eMail: rgtsbs@erols.com

Robert G. Towers
Basil L. Copeland, Jr.
David E. Peterson

RECEIVED
AUG 13 2004
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

July 22, 2004

via eMail and US Mail
David A. Jacobson, Utility Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, South Dakota 57501

RE: Report and Consulting Service Proposal
Montana-Dakota Utilities Co. (Gas rates)
SDPUC Docket No. NG04-004

Dear Dave:

Thank you for sending the MDU rate filing for our comments, suggestions and a proposal to assist Commission Staff. To that end, I have reviewed the filing statements and testimony and discussed the Company's cost of capital presentation with Basil Copeland.

Overview of the Filing

On June 4, 2004, MDU filed with the Commission an Application seeking an increase in rates for gas service in its Black Hills service area. The proposed rates were designed to increase its annual revenue from these customers by $1,281,417, which is described as a 2.2% increase (Statement O). However, because MDU's on-going purchased gas costs are recovered through an independent PGA and are not a component of the general rate increase now being proposed, the increase it proposes here is more appropriately viewed as an overall 10.7% increase in its existing base rate revenue. These rates became effective six months earlier, for service rendered on and after December 2, 2003 as the result of a Settlement of the Company's January, 2003 filing in Docket No. NG02-011.

MDU serves 43,100 customers on its Black Hills system, including 37,900

Residential users, 5,100 Firm General Service customers, Ellsworth Air Force base, one contract service customer (Merillat), 8 interruptible sales customers and 38 interruptible transportation service customers (Statement O).

The revenue requirement determination filed in support of MDU's proposed rates is developed using an actual base year ended December 31, 2003 (Statement M, page 1), with numerous thinly-supported adjustments (Stmt. M, pages 2-5) to reflect a "pro forma" year 2003 (Stmt. M, page 7). The far-reaching nature of the pro forma adjustments leads, ultimately, to labeling the test period "Pro Forma 2004" (Stmt. N). Thirty-one Operating income adjustments were made to normalize the effects of weather on sales, to annualize the Docket No. NG02-011 rate increase, to reflect current (June 1, 2004) PGA revenues and gas costs, to reflect projected increases in firm service customers and reduced sales and transportation volumes projected to occur by the end of 2004, and to reflect estimated payroll costs and budgeted benefits costs, including the costs of the key employee Supplemental Income Security Plan, etc. Substantial increases in Vehicle and Work Equipment costs (reflecting mileage-based depreciation) and Computer rental expenses are claimed as is a claim for "institutional" advertising. Rate case expense is claimed, including overlapping costs for both NG02-011 and the present case.

Rate base adjustments are made primarily to reflect $2.9 million in post-2003 plant additions expected to be in service by December 31, 2004. However, the claimed rate base reflects the average of the 2004 beginning of year and year end plant and accumulated depreciation balances (Stmt. D, page 1) and no claim is made for cash working capital.

The Company shows that its unadjusted income and rate base for the base year 2003 allowed it to earn a 4.180% return on rate base. (Of course, this reflects only a partial month's benefit of the Docket NG02-011 rate increase.) With all of the claimed pro forma adjustments, including a full year's effect of the December 2003 rate increase, it projects that it will earn a 5.264% rate of return in 2004 (Stmt. M, page 1). To achieve its proposed 9.613% return on rate base, reflecting a proposed 11.0% return on common equity, requires the proposed $1.28 million increase in base rate revenue.

The proposed return on rate base reflects Montana-Dakota Utilities, Co.'s projected embedded debt and preferred stock costs and projected capital structure with equity reductions for unregulated subsidiaries (Stmt. G). The capital structure also includes an $18.0 million equity infusion in 2004, together with a $14.7 million increase in retained earnings. The 11.0% return on equity is recommended by a

consultant, Dr. Stephen Gaske, based on various DCF analyses of a proxy group of gas distribution companies and multiple risk premium and "alternative investments" analyses (Gaske, pp. 32-35).

Based on conclusions drawn from its analysis of service costs by customer class (Stmt. N), MDU recommends that the proposed 2.2% increase in combined base rate and PGA revenues be recovered as follows:

Residential	2.9% increase
Firm General Svc.	2.0% "
Firm Contract Svc.	No increase
Air Force	No increase
Small Interruptible	No increase
Large Interruptible	1.0% "

(Exhibit___(TAA-1)

By this distribution of the increase, all "excess" (above the requested rate of return) returns earned from Contract and Small Interruptible customers are used to minimize the rate increases to Residential, SGS and and Large Interruptible users. [1] The rate increases to SGS and Large Interruptible users are designed to match the returns from these classes with the overall, requested rate of return. Thus, the resulting Residential class rate of return is projected to be below the system average.

The Company would retain its existing (established in Docket No. NG02-011) three-part rates consisting of a per day Basic Service Charge", a volumetric Distribution Charge and a Cost of Gas component. It would also retain the Distribution Delivery Stabilization Mechanism established in the last case in lieu of much higher service charges that had been requested there. The Residential Service Charge is increased by one cent per day to $0.26 (a monthly equivalent of $7.90) based on the level of "customer costs" derived in its class cost of service study (CCOSS). For SGS customers these increases are two or four cents, depending on meter size.

The proposed single-step distribution delivery charges recover all non-gas costs which are not recovered in the basic service charge. The cost of gas component, or PGA, is adjusted in MDU's monthly PGA filings with the Commission.

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[1] This is evident in the before and after-rate-increase rates of return displayed on page 1, Schedule O-1 of Stmt. O.

Potential Issues and Division of Workload

MDU's filing raises issues similar to many of the issues which Staff dealt with in the 2003 (NG02-011) filing. In this filing, revenue requirement issues relate to the extensive and necessarily speculative adjustments which the Company has made to reflect conditions anticipated in 2004.

The Company again requests rate recovery of the costs of its "Supplemental Income Security Plan", or "SISP". SISP "provides a supplemental pension benefit to key employees... to attract and retain key employees (see testimony of Paul W. Conley, page 2). The plan was established in 1982 but, until its NG02-011 rate filing, the costs have been reflected below-the-line. Here, the Company claims $198,846 for the South Dakota gas operations share of the SISP program. This is equivalent to $4.60 per customer annually and is substantially more than the $120,000 claimed in Docket NG02-011. SISP costs were not reflected in the Settlement of that case.

MDU continues to use depreciation rates which were developed in a 2001 study by its consultants, AUS. Based on the most recent documented analysis of MDU's depreciation requirements, we objected to the results of using the AUS rates for Mains and Services and believe that Staff's position was reflected in the Settlement of that case. The AUS-based rates are somewhat lower here (for each account, AUS established separate rates based on the pipe material; thus the rates for each account as a whole changes as the material mix changes), but the earlier study, we believe, supports still lower rates for these accounts.

One issue which we raised in the last case – consolidated tax savings – appears to be no longer viable because, unlike in the last case, MDU's South Dakota gas operations now generate a negative current income tax liability – even at the proposed rate level. While the reasons for this change should be explored, if those reasons are sound, the tax liability cannot be further reduced.

Another issue addressed in prior cases, but not in MDU's filing here, is its rate base reduction for Accumulated deferred investment tax credits. By virtue of MDU's IRCode election, regulators are prohibited from recognizing these tax savings by doing more than reducing rate base -- i.e. there can be no reduction in tax expense by a ratable amortization. But MDU has minimized the rate base reduction by amortizing the tax credits over 20 years rather than the longer average service lives of its plant. Staff has corrected this problem in past cases and should do so here.

The 11.0% return on equity reflected in the proposed rate of return is an important issue. A fundamental flaw in Gaske's approach is his use of proxy *natural gas* utilities to determine the cost of equity for a *combination gas and electric* utility. Assessing MDU's cost of equity directly, or by reference to combination companies also would be consistent with the application of that equity cost, as MDU proposes, to its own capital structure supporting both operations. The NG02-011 case ROE issue was settled at a fraction above 10.0%.

The class cost allocations used to support the class-by-class distribution of the proposed increase and to support any further increase in customer Service Charges are distorted by classifying as "customer costs" a significant portion of distribution Mains. As in the last case, eliminating this bias in the allocations will shift cost responsibility away from Residential and other small users and onto the larger customers. Similarly, it will reduce the "customer costs" offered in support of the Service Charges. Moreover, even though the proposed increases in Service Charges are relatively small, we would question whether any increase is justified at this time in light of the facts that (1) these charges were increased as recently as December, 2003 as a result of the Settlement of NG02-011 and (2) that Settlement also established the Distribution Delivery Stabilization Mechanism as an alternative to higher Service Charges.

With precedent to guide the Staff on the familiar issues, it would be logical to have Staff review and make decisions on the recurring adjustments including weather normalization and other sales adjustments, labor costs, advertising, miscellaneous and general expenses, rate base adjustments for plant additions, etc.

On many other issues, including SISP, depreciation, income taxes, etc. we propose to work with your in-house Staff to develop an investigation plan and to assist in analyzing the issues and formulating recommendations. Jointly, we could determine whether CRC or Staff should present testimony on the issue.

We propose to address the cost of capital, class cost allocation and rate design issues, with as much participation as possible by your staff.

Proposal

As you know, we have considerable experience with general rate increase requests for natural gas utilities similar to MDU. In addition to our participation in the recent (and earlier) MDU cases, the current and prior MidAmerican and NWPS gas

cases in South Dakota, we have recently been engaged for gas and electric rate cases by the Colorado Consumer Counsel, the New Jersey Ratepayer Advocate and the West Virginia Consumer Advocate.

In this proceeding, we propose to assist the Staff as described above. Basil Copeland would be the witness on cost of capital and capital structure issues. I would be the witness sponsoring any accounting issues that are delegated to me by your Staff, and the class cost of service and revenue distribution issues. Dave Peterson will be assisting me, as needed, on all issues and in preparing the class cost of service and rate design studies and exhibits.

We will prepare the necessary data requests to elicit the information needed for our analyses; review the Company's responses, confer with their witnesses and other personnel, as necessary; prepare testimony and supporting exhibits describing our analyses, findings and recommendations; and, as needed, we will assist Staff witnesses in developing issues on which they will testify. We will also assist Staff Counsel in preparing for hearing and with the preparation of post-trial briefs and other pleadings. For the purposes of preparing a cost estimate, I have assumed that two or three days will be required for participation in hearings in Pierre.

We estimate that the cost of performing these services would amount to approximately $46,025, including out-of-pocket expenses. Of course we would bill only for time actually spent working on the assignment and for our actual out-of-pocket costs, principally for air fare for 2 man-trips to Pierre, per diem expenses in Pierre, long distance telephone, copier and courier services. Our estimate is derived as follows:

Tasks	Hours		
	Towers	Copeland	Peterson
• Analyze the filing, identify issues, discovery;	46	28	12
• Preparation of testimony and exhibits, including coordination with other Staff witnesses;	36	34	38
• Review rebuttal testimony and preparation for hearing;	36	20	20
• Participation in hearing	24	16	-
• Assisting counsel with briefs	14	10	-
Total hours	156	108	70

Cost Summary

Fees: Towers	156 hrs. @ $135		$21,060
Copeland	108 hrs. @ $130		14,040
Peterson	70 hrs. @ $125		8,750
Out-of-pocket expenses:			
Air fare	$1,500		
Hotel	200		
Courier	125		
Data base charges for ROE analysis		250	
Other	100		
			2,175
Total cost			$46,025
Rounded			**$46,025**

Please let me know if you have any questions about my discussion of the issues, division of the workload between your Staff and our firm or any other aspect of this report/proposal. We look forward to working with you again.

Sincerely,

Robert G. Towers
President

Attachment: Fee Schedule (April, 2004)

RECEIVED
AUG 16 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

CONTRACT BETWEEN CHESAPEAKE REGULATORY CONSULTANTS, INC. AND THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

This Contract is entered into this 16th day of August, **2004**, between the **South Dakota Public Utilities Commission** (Commission) and Chesapeake Regulatory Consultants, Inc. (Contractor), of 6837 Guilford Road, Clarksville, Maryland 21029-1632. The terms and conditions are as follows:

1. **Scope of Services:** Contractor agrees to provide consulting services to the Staff of the Commission in the following Commission Docket: NG04-004, In the Matter of the Application of Montana-Dakota Utilities Co. for Authority to Increase Rates for Natural Gas Service.

Contractor agrees to assist Commission Staff in the preparation and presentation of testimony on behalf of Commission Staff in the above-referenced docket including: at hearings before the Commission; in settlement proceedings; and in the preparation of motions and briefs before the Commission. Contractor through its witness or witnesses, Basil L. Copeland Jr. and Robert G. Towers shall be responsible for: review and analysis of Montana-Dakota Utilities Co. (MDU) filings, preparation and receipt of data requests necessary to complete the analysis, preparation, filing and presentation of testimony and exhibits.

Contractor shall also be prepared to respond at hearings and during briefing to intervenors' submissions, if any, which address the issues which are the responsibility of Contractor. Specifically, Contractor Witness Basil L. Copeland Jr. shall prepare, file, and present testimony and exhibits related to the appropriate costs of capital and capital structure. Contractor Witness Robert G. Towers shall prepare, file, and present testimony and exhibits addressing class cost of service study issues, rate design, accounting issues that may arise, and possibly other issues delegated to Contractor by Commission Staff. Contractor shall provide general assistance on the filing when requested to do so by Commission Staff.

The scope and tasks to be performed shall be consistent with Contractor's proposal dated July 22, 2004, to Commission Staff. Contractor agrees to coordinate their filings with Commission Staff and as directed by Commission Staff, shall consult Commission Staff on requests for MDU data and other submissions or requests to MDU or intervenors. Contractor agrees to complete all tasks and filings within time frames as determined by Commission Staff.

It is understood and agreed that the role of Commission Staff, and in turn the role of the Contractor, shall be to advocate the public interest as Commission Staff views that public interest.

2. **Maximum Reimbursement:** The Commission agrees to reimburse the Contractor for satisfactory completion of Contractor's services in an amount not to exceed **Forty-six thousand twenty five dollars and no cents ($46,025.00)**. Services shall be paid for on the basis of time actually spent working on the case and for actual out-of-pocket costs at rates consistent with Contractor's proposal to Commission Staff dated July 22, 2004, which is incorporated by reference into this document.

If the Contractor desires to increase the maximum reimbursement under this paragraph, Contractor must notify the South Dakota Public Utilities Commission Executive Director in writing not less than thirty (30) days before monthly billings reach the maximum reimbursement. The Commission reserves the right to deny any request for an increase and may hold the Contractor to the maximum reimbursement in the original contract or amendment.

3. **Reimbursement:** The Commission agrees to reimburse the Contractor upon satisfactory progress toward completion of the tasks outlined in Paragraph 1 of this Contract. Payment up to the amount specified in the Maximum Reimbursement paragraph herein shall be made in monthly installments and shall be based on the monthly financial report as described herein. A copy of the Contractor's hourly fee schedule is appended to this Contract as Exhibit A, which is hereby incorporated herein and will remain effective throughout the term of this Contract.

A monthly invoice shall be submitted by the Contractor which shall describe the nature of the work performed and show, for each consultant, the hours worked and associated fees and list all charges for Contractor's out-of-pocket expenses. Receipts for such expenses shall be available to the Commission upon request. This information is for the express purpose of internal auditing by the Commission. When requesting payment, the time period or phase of service covered will be indicated on the face of the invoice.

The Contractor may not receive progress payments more frequently than monthly. Progress payments shall be based on services rendered and no payment may be made in advance of services rendered. It is agreed that the Commission may withhold ten percent of each progress payment until the satisfactory completion of the contract. Invoices for services rendered shall be sent to the South Dakota Public Utilities Commission, Deputy Executive Director, State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota 57501, within ten (10) days of the calendar month billed.

4. **Consideration:** The consideration to be paid the Contractor as provided herein shall be in compensation for all Contractor's services incurred in the performance hereof.

5. **Change in Scope of Services:** If the scope of services under this Contract is modified to require additional work not herein contemplated and such modification is approved by the parties herein prior to performance and a written amendment to this Contract is drawn identifying the approved changes, an authorization of additional funds will be made by the Commission and the maximum amount will be appropriately increased.

6. **Indemnity:** The Contractor agrees to indemnify, defend and hold harmless the State, its officers, agents and employees from any and all claims and losses accruing or resulting to any and all contractors, subcontractors, material men, laborers and any other person, firm or corporation furnishing or supplying work, services, materials or supplies in connection with the performance of this Contract and from any and all claims and losses accruing or resulting to any person, firm or corporation who may be injured or damaged by the Contractor in the performance of this Contract.

7. **Independent Contractor:** The Contractor and the agents of the Contractor in performance of this Contract shall act in an independent capacity and not as officers, employees or agents of the Commission.

8. **Contract Not Assignable:** This Contract is not assignable by the Contractor, either in whole or in part, without the written consent of the Commission.

9. **Alteration and Oral Agreements:** No alteration or variation of the terms of this Contract shall be valid unless made in writing and signed by the parties hereto. No oral understanding or agreement not incorporated herein may be binding on any of the parties hereto.

10. **Interpretation of Inconsistencies:** In the interpretation of this Contract, any inconsistencies between the terms hereof and the attachments shall be resolved in favor of the terms hereof.

11. **Subcontracts:** Contractor shall submit any subcontracts which he proposes to enter into to the Commission for its prior written approval before the Contractor enters into the same. No work may be subcontracted without the prior approval of the Commission. Upon the termination of any subcontract, the Commission shall be notified immediately.

12. **Retention of Contractor's Records:** The Contractor shall retain all records relating to direct expenses reimbursed to the Contractor hereunder and to hours of employment on this Contract by any employee of Contractor for which the Commission is billed. Such records shall be maintained for a period of three years

after termination of this Contract and shall be available for inspection at any reasonable time by personnel authorized therefore by the State of South Dakota.

13. Relationship of Commission Staff and Contractor: Commission Staff will be permitted to work side-by-side with Contractor's Staff to the extent and under conditions that may be directed by the Executive Director of the Commission.

14. Contractor Responsible for Performance of Services: Contractor will not be permitted to utilize Commission personnel for the performance of services which are the responsibility of Contractor, unless such utilization is previously agreed to in writing by the Executive Director and any appropriate adjustment in price is made. No charge will be made to Contractor for the services of Commission employees while performing coordinating or monitoring functions.

15. Disclosure and Confidentiality: The Contractor will not disclose data or disseminate the contents of any final or preliminary report or testimony, in any form, in regard to this Contract without express written consent of the Commission. Permission to disclose information on one occasion shall not authorize Contractor to further disclose such information or disseminate the same on any other occasion.

If requested by the Commission, the Contractor shall require each of its employees or officers who will be involved in the performance of this Contract to agree to the above terms in a form to be approved by the Commission and shall supply the Commission with evidence thereof.

Each subcontract shall contain provisions similar to the foregoing, related to the confidentiality of data and non-disclosure of the same.

16. Data is Property of the Commission: Data developed for this Contract shall become the property of the Commission. It shall not be disclosed without the permission of the Executive Director. Each final report submitted shall also become the property of the Commission and shall not be disclosed except in such manner and time as the Executive Director may direct.

17. Amendment: The timing for the performance of the tasks and items contained herein, the total contract price, the date for completion of the Contract, as well as, all other terms not specifically accepted may only be altered by formal written amendment of this Contract.

18. Waiver: No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach. All remedies afforded in this Contract shall be taken and construed as cumulative; that is, in addition to every other remedy provided therein or by law. The failure of the Commission to enforce, at any time, any of the provisions of the Contract shall in no way be construed to be a waiver of such provisions, nor in any way affect the validity of this Contract or any part thereof,

or the right of the Commission to hereinafter enforce each and every such provision.

19. Time is Critical: Time is of the essence in this Contract. In the event Contractor shall fail to perform the agreements on its part to be performed at the time fixed for performance of such respective agreements by the terms of this Contract or by any extension, the Commission may, at its election, terminate the Contract. Such termination shall be in addition to and not in lieu of any other legal remedies provided by this Contract or by law.

20. Breach of Contract: In the event of any breach of this Contract, the Commission may, without any prejudice to any of its other legal remedies, terminate this Contract in accordance with the provisions of the Termination paragraph of this Contract.

21. Duration of Contract: Unless otherwise specifically provided by the terms of this Contract or by amendment thereof, the duration of this Contract shall be one year from the contract date.

22. Termination: The Commission may terminate this Contract, should Contractor fail to perform the covenants herein contained at the time and in the manner herein provided, upon five days written notice to the Contractor. In such event, the Commission shall pay the Contractor only the reasonable value of the services theretofore rendered by the Contractor as may be agreed upon by the parties or determined by a court of law. In the event of such termination, the Commission may proceed with the work in any manner deemed proper by the Commission. The Commission's cost of securing substituted performance shall be deducted from any sum due the Contractor under this Contract, with the balance, if any, to be paid the Contractor upon demand.

23. Payments Include All Taxes: Payments to be made to the Contractor, as specified herein, shall include all taxes of any description, federal, state and municipal assessed against the Contractor by reason of this Contract.

24. Workers' Compensation Insurance: The Contractor hereby warrants that it carries workers' compensation insurance for all of its employees who will be engaged in the performance of this Contract and agrees to furnish to the Commission satisfactory evidence thereof at any time the Commission may request.

25. South Dakota Law Controlling: It is expressly understood and agreed that this Contract shall be governed by the laws of the State of South Dakota, both as to interpretation and performance. Otherwise, as specified herein, no document or communications passing between the parties hereto shall be deemed a part of this Contract.

APPROVED AS TO FORM:

Karen E. Cremer — August 16, 2004

Karen E. Cremer, Special Assistant Attorney General — DATE

COMMISSION:

ROBERT K. SAHR	GARY HANSON	JAMES A. BURG
Chairman	Commissioner	Commissioner

CONTRACTOR:

By: _____ 8/12/04

Robert G. Towers — Date

Chesapeake Regulatory Consultants, Inc.,

its President.

Chesapeake Regulatory Consultants, Inc.

6837 Guilford Road
Clarksville, MD 21029-1632

Phone: 443.535.0300 Fax: 443.535.0301
eMail: rgtsbs@erols.com

Robert G. Towers
Basil L. Copeland, Jr.
David E. Peterson

Exhibit A

FEE SCHEDULE

		Hourly Rate
Robert G. Towers	Senior Consultant	$ 135.00
Basil L. Copeland, Jr.	Senior Economist	$ 130.00
David E. Peterson	Senior Consultant	$ 125.00

April 1, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	**ORDER FOR AND NOTICE OF PROCEDURAL SCHEDULE AND HEARING NG04-004**

On June 7, 2004, Montana-Dakota Utilities Co. (MDU), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in its Black Hills service territory. The application seeks an increase in rates in the approximate amount of $1,281,417 or approximately 2.2%. On June 22, 2004, the Commission suspended the proposed schedule of rates for 90 days beyond June 7, 2004.

At its regularly scheduled meeting of June 22, 2004, the Commission found that pursuant to SDCL 49-1A-8, MDU shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 9, 2004.

On July 15, 2004, Commission Staff advised the Commission that the suspension should have been for 90 days beyond July 7, 2004. On July 20, 2004, pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by MDU for 90 days beyond July 7, 2004. The Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26 and 49-34A, specifically 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-17, 49-34A-19, 49-34A-21.

The procedural schedule for testimony shall be as follows:

DATE	PROCEDURAL SCHEDULE
October 4, 2004	Staff Prefiled Testimony Due
October 14, 2004	MDU Rebuttal Testimony Due
October 19 and 20, 2004	Hearing
November 8, 2004	Initial Briefs Due
November 15, 2004	Rebuttal Briefs Due

A hearing shall be held beginning at 9:00 a.m., on Tuesday, October 19, 2004, and beginning at 8:30 a.m. on Wednesday, October 20, 2004, in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota. The hearing is open to the public. All persons testifying shall be subject to cross-examination.

The issue at the hearing is whether the Commission shall grant MDU's request to implement revised natural gas rate schedules designed to produce additional revenues of $1,281,417.

The hearing shall be an adversary proceeding conducted pursuant to SDCL Chapter 1-26. All parties have the right to be present and to be represented by an attorney. These rights and other due process rights shall be forfeited if not exercised at the hearing. If you or your representative fail to appear at the time and place set for the hearing, the Final Decision will be based solely on the testimony and evidence provided, if any, during the hearing or a Final Decision may be issued by default pursuant to SDCL 1-26-20. After the hearing the Commission will consider all evidence and testimony that was presented at the hearing. The Commission will then enter Findings of Fact, Conclusions of Law, and a Final Decision regarding this matter. As a result of this hearing, the Commission shall determine whether it shall grant MDU's request to implement revised rate schedules. The Commission's Final Decision may be appealed by the parties to the state Circuit Court and the state Supreme Court as provided by law. It is therefore

ORDERED, that the procedural schedule set forth above shall be followed by all parties to these proceedings. It is further

ORDERED, that the hearing shall commence at 9:00 a.m., on Tuesday, October 19, 2004, in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota, and if necessary, shall continue through Wednesday, October 20, 2004.

Pursuant to the Americans with Disabilities Act, this hearing is being held in a physically accessible location. Please contact the Public Utilities Commission at 1-800-332-1782 at least 48 hours prior to the hearing if you have special needs so arrangements can be made to accommodate you.

Dated at Pierre, South Dakota, this 26th day of August, 2004.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 8/27/04

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

ROBERT K. SAHR, Chairman

GARY HANSON, Commissioner

JAMES A. BURG, Commissioner

Bob Sahr, Chair
Gary Hanson, Vice-Chair
Jim Burg, Commissioner

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

500 East Capitol Avenue
Pierre, South Dakota 57501-5070
www.state.sd.us/puc

Capitol Office
(605) 773-3201
(605) 773-3809 fax

Transportation/Warehouse
(605) 773-5280
(605) 773-3225 fax

Consumer Hotline
1-800-332-1782

October 1, 2004

RECEIVED
OCT 01 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Pam Bonrud
Executive Director
500 E. Capitol
Pierre, SD 57501

RE: Montana-Dakota Utilities Co. rate case
NG04-004

Dear Ms. Bonrud:

Pursuant to the Order for and Notice of Procedural Schedule and Hearing that was filed in the above-referenced matter, Staff was to have filed its prefiled testimony on October 4, 2004. Due to the delay in getting timely responses to Staff's data requests, Staff and MDU have agreed to revise the procedural schedule as follows:

DATE	PROCEDURAL SCHEDULE
October 19, 2004	Staff Prefiled Testimony Due
October 29, 2004	MDU Rebuttal Testimony Due
November 4 and 5, 2004	Hearing
November 23, 2004	Initial Briefs Due
November 30, 2004	Rebuttal Briefs Due

If you have any questions, please do not hesitate to contact me.

Sincerely,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

cc: Dave Gerdes

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	**AMENDED ORDER FOR AND NOTICE OF PROCEDURAL SCHEDULE AND HEARING NG04-004**

On June 7, 2004, Montana-Dakota Utilities Co. (MDU), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in its Black Hills service territory. The application seeks an increase in rates in the approximate amount of $1,281,417 or approximately 2.2%. On June 22, 2004, the Commission suspended the proposed schedule of rates for 90 days beyond June 7, 2004.

At its regularly scheduled meeting of June 22, 2004, the Commission found that pursuant to SDCL 49-1A-8, MDU shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 9, 2004.

On July 15, 2004, Commission Staff advised the Commission that the suspension should have been for 90 days beyond July 7, 2004. On July 20, 2004, pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by MDU for 90 days beyond July 7, 2004. The Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26 and 49-34A, specifically 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-17, 49-34A-19, 49-34A-21.

The procedural schedule for testimony shall be as follows:

DATE	**PROCEDURAL SCHEDULE**
October ~~4~~ 19, 2004	Staff Prefiled Testimony Due
October ~~14~~ 29, 2004	MDU Rebuttal Testimony Due
~~October 19 and 20~~ November 4 and 5, 2004	Hearing
November ~~8~~ 23, 2004	Initial Briefs Due
November ~~15~~ 30, 2004	Rebuttal Briefs Due

A hearing shall be held beginning at 9:00 a.m., on ~~Tuesday~~ Thursday, ~~October 19~~ November 4, 2004, and beginning at 8:30 a.m. on ~~Wednesday~~ Friday, ~~October 20~~ November 5, 2004, in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota. The hearing is open to the public. All persons testifying shall be subject to cross-examination.

The issue at the hearing is whether the Commission shall grant MDU's request to implement revised natural gas rate schedules designed to produce additional revenues of $1,281,417.

The hearing shall be an adversary proceeding conducted pursuant to SDCL Chapter 1-26. All parties have the right to be present and to be represented by an attorney. These rights and other due process rights shall be forfeited if not exercised at the hearing. If you or your representative fail to appear at the time and place set for the hearing, the Final Decision will be based solely on the testimony and evidence provided, if any, during the hearing or a Final Decision may be issued by default pursuant to SDCL 1-26-20. After the hearing the Commission will consider all evidence and testimony that was presented at the hearing. The Commission will then enter Findings of Fact, Conclusions of Law, and a Final Decision regarding this matter. As a result of this hearing, the Commission shall determine whether it shall grant MDU's request to implement revised rate schedules. The Commission's Final Decision may be appealed by the parties to the state Circuit Court and the state Supreme Court as provided by law. It is therefore

ORDERED, that the procedural schedule set forth above shall be followed by all parties to these proceedings. It is further

ORDERED, that the hearing shall commence at 9:00 a.m., on ~~Tuesday~~ Thursday, ~~October 19~~ November 4, 2004, in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota, and if necessary, shall continue through ~~Wednesday~~ Friday, ~~October 20~~ November 5, 2004.

Pursuant to the Americans with Disabilities Act, this hearing is being held in a physically accessible location. Please contact the Public Utilities Commission at 1-800-332-1782 at least 48 hours prior to the hearing if you have special needs so arrangements can be made to accommodate you.

Dated at Pierre, South Dakota, this 4th day of October, 2004.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 10/5/04

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

Robert K. Sahr

ROBERT K. SAHR, Chairman

Gary Hanson

GARY HANSON, Commissioner

James A. Burg

JAMES A. BURG, Commissioner

Bob Sahr, Chair
Gary Hanson, Vice-Chair
Jim Burg, Commissioner

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

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(605) 773-3809 fax

Transportation/Warehouse
(605) 773-5280
(605) 773-3225 fax

Consumer Hotline
1-800-332-1782

October 19, 2004

Mr. Donald R. Ball
Assistant Vice President - Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501

Mr. Douglas W. Schulz
Associate General Counsel and Assistant Secretary
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Mr. David A. Gerdes
Attorney at Law
May, Adam, Gerdes & Thompson LLP
P. O. Box 160
Pierre, SD 57501-0160

Re: In the Matter of the Filing by Montana-Dakota Utilities Co. for Authority to Increase Rates for Natural Gas Service
Docket NG04-004

Gentlemen:

Enclosed each of you will find copies of testimony of David A. Jacobson, Michele M. Farris, Martin C. Bettmann, Keith A. Senger, Basil L. Copeland, Jr. and Robert G. Towers with reference to the above captioned matter. This is intended as service upon you by mail.

Very truly yours,

Karen E. Cremer
Staff Attorney

KEC:dk
Enc.

cc: Mr. Robert G. Towers
Mr. Basil L. Copeland, Jr.
Mr. Dave Peterson
Enc.

RECEIVED
OCT 15 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES
DOCKET NO. NG04-004

TESTIMONY AND EXHIBITS OF MICHELE M. FARRIS
ON BEHALF OF THE COMMISSION STAFF
OCTOBER 2004

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Montana-Dakota Utilities
Docket No. NG04-004

Testimony of Michele M. Farris
On Behalf of Commission Staff

October 2004

Q. Please state your name, business address and current position.

A. My name is Michele M. Farris and my business address is Public Utilities Commission, 500 East Capitol, Pierre, SD 57501. I am presently employed as a Utility Analyst.

Q. Please describe your educational background and experience.

A. I received a Bachelor of Science degree in Mechanical Engineering from South Dakota State University in May 1987. I received a Master of Science degree in Civil Engineering from the University of Colorado in May 1994. I am a registered Professional Engineer in the State of South Dakota. I commenced employment with the Public Utilities Commission in January 1999.

Q. Have you previously presented testimony before the Commission?

A. Yes. I have presented testimony in four rate case filings, Docket NG02-011, Docket NG01-010, Docket NG99-002, and Docket NG98-011, requesting an increase in gas rates for Montana Dakota Utilities, MidAmerican Energy Company, NorthWestern Public Service, and MidAmerican Energy Company, respectively. In addition, I have presented testimony in the following dockets: Docket GE00-002, request by The Dunham Company for a master metering variance; Docket NG01-004, request by Floyd Nightingale for a master metering variance; Dockets EL00-002, EL00-003, and EL00-009, regarding approval of a departure from its fuel clause adjustment for Otter Tail Power Company, Montana-Dakota Utilities Company, and NorthWestern Public Service, respectively; and Docket TC99-005 regarding the sale of stock for Union Telephone Company of Hartford and Armour Independent Telephone Co.,

including its wholly-owned subsidiary, Bridgewater-Canistota Independent Telephone Co. to MJD Services Corp.

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

A. I shall express my opinion regarding adjustments to Montana-Dakota Utilities' charitable contribution expenses, economic development expenses, industry and association dues, chamber dues, advertising expenses, and rate case expense.

Q. Did Montana-Dakota Utilities include charitable contribution expenses in the South Dakota test year expenditures?

A. No. Montana-Dakota Utilities has charged charitable contributions as a below the line item for rate making purposes. No charitable contribution amounts were included in South Dakota test year expenditures.

Q. Based on your education and experience, what is your opinion in regard to Montana-Dakota Utilities' claimed association dues?

A. It is my opinion that an adjustment of ($31,301) be made to Montana-Dakota Utilities' cost of service (see Exhibit__(MMF-1), Schedule 1). The organizational dues, which were excluded, consist of payments to various Chambers of Commerce and economic development organizations. Membership in these organizations is not necessary for MDU's rendition of safe, adequate and reliable gas service in South Dakota. Also, MDU should not be allowed to force ratepayers to contribute to organizations with which they may not be in agreement.

Membership in the organizations listed in "other" is not necessary for the rendition of safe, adequate and reliable gas service in South Dakota. Therefore, membership dues should not be recovered from ratepayers. The bulk of the "other" dues are for membership to the Utility Shareholders of South Dakota, which was established as an independent organization in the state to represent the collective interests, rights and concerns of utility investors in South Dakota.

Q. Based on your education and experience, what is your opinion regarding institutional/promotional/goodwill advertising expenses?

A. It is my opinion that an adjustment of ($32,142) be made to Montana-Dakota Utilities' cost of service (see Exhibit__(MMF-1), Schedule 2). The advertising

expenses charged to account 909 are for gas safety advertisements. I recommend that all of MDU's gas safety advertisements be allowed in rates. Montana-Dakota Utilities has proposed to eliminate all test year costs in account 913, promotional advertising, in its adjustment. The advertising expenses charged to account 930.1 are for institutional advertising. I recommend the $5,647 spent on institutional advertising be disallowed. Institutional advertising serves only to enhance the image of MDU and should not be paid by ratepayers and Commission precedent has long recognized this.

Q. Based on your education and experience, what is your opinion regarding economic development expenses proposed by Montana-Dakota Utilities to be included in rates?

A. The Company has included $776 for economic development expenses in account 912. I recommend this amount be disallowed (see Exhibit __(MMF-1), Schedule 3.) As mentioned in prior testimony regarding organizational dues, MDU has listed expenditures to Black Hills Community Economic Development, Inc. and Rapid City Area Economic Development Corp. MDU has no formal economic development plan in place that demonstrates the ratepayer is benefiting from the expenditure. If MDU wants to include economic development expenses in rates they must develop a program whereby the ratepayer and the shareholder share in the cost of the program.

Q. What are you recommending with regard to Montana-Dakota Utilities' rate case expense?

A. MDU is requesting a rate case expense of $154,437 amortized over three years, which includes a recurring regulatory expense of $658 per year. Staff is proposing a rate case expense of $37,982, which also includes a recurring regulatory expense of $658 per year. Staff's rate case expense is based on expenses incurred through September 30, 2004 for both MDU and Staff (see Exhibit __(MMF-1), Schedule 4.)

Q. What amortization period is proposed by Staff?

A. Staff proposes to amortize the rate case expense over five years. Although the company filed this case within two years of the previous case NG02-011, the prior

rate case adjustment was filed in 1994, NG94-012. Therefore, Staff believes a five year amortization period is fair. In addition, staff proposes to place one-half of the rate case expense into rate base. The company will earn a reasonable return on their rate case expense and a return on investment through rates over a five-year period.

Q. Does that conclude your testimony?

Yes.

Montana-Dakota Utilities
South Dakota-Gas
Industry Association Dues
Test Year Ended December 31, 2003

Exhibit__(MMF-1)
Schedule 1
Page 1 of 1

	(a)	Company Per Books (b)	Staff Adjustments (c)
1	American Gas Association	$ 8,731	$ 538
2	Black Hills Community Economic Development, Inc.	$ 249	$ 249
3	Chamber of Commerce - Belle Fourche	$ 499	$ 499
4	Chamber of Commerce - Deadwood	$ 250	$ 250
5	Chamber of Commerce - Lead Area	$ 150	$ 150
6	Chamber of Commerce - Rapid City Area	$ 6,790	$ 6,790
7	Chamber of Commerce - Spearfish	$ 599	$ 599
8	Chamber of Commerce - Sturgis	$ 574	$ 574
9	Energy Safety Association	$ 1,103	
10	Midwest Energy Association	$ 2,147	
11	NARUC	$ 204	
12	Rapid City Area Economic Development Corp.	$ 3,500	$ 3,500
13	United Telecom Council	$ 350	$ 350
14	Other	$ 17,802	$ 17,802
	Total	$ 42,948	$ 31,301
15	Staff adjustment		$ (31,301)

Sources:

Column b, Lines 11-26: Statement H, Schedule H-1, Page 15 of 21
Column c, Line 1: Data Response 1-4 Attachment A, Statement H pages 65 - 67
Column c, Line 9: Data Response 1-4 Attachment A, Statement H page 64
Column c, Line 10: Data Response 1-4 Attachement A, Statement H page 64
Column c, Line 11: Data Response 1-4 Attachment A, Statement H page 64

Montana-Dakota Utilities
South Dakota-Gas
Institutional/promotional/goodwill advertising
Test Year Ended December 31, 2003

Exhibit__(MMF-1)
Schedule 2
Page 1 of 1

	(a)	Advertising Expenses Per Books (b)	Company Pro Forma Adjustments (c)	Staff Adjustments (d)
1	Account 909 Informational Advertising	$ 12,081		
2	Account 913 Promotional Advertising	$ 26,495	$ 26,495	$ 26,495
3	Account 930.1Institutional Advertising	$ 5,647	$ 148	$ 5,647
	Total	$ 44,223	$ 26,643	$ 32,142
4	Company Pro Forma adjustment		$ (26,643)	
5	Staff adjustment to per books			$ (32,142)

Sources:

Column b, c and d, Lines 11,12, 13 : Statement H, Schedule H-1, Page 16 of 21

Montana-Dakota Utilities
South Dakota-Gas
Economic Development
Test Year Ended December 31, 2003

Exhibit__(MMF-1)
Schedule 3
Page 1 of 1

	(a)		Other O & M Expenses Per Books (b)	Staff Adjustments (c)
1	Sales		$ 187,077	
2	Account 912 Economic Development			$ 776
		Total	$ 187,077	$ 776
4	Staff adjustment to account 912			$ (776)

Sources:

Column b, Line 1: Statement H, Page 3 of 3
Column c, Line 2 & 3: Data Response 1-27

Montana-Dakota Utilities
South Dakota-Gas
Rate Case Expense
Test Year Ended December 31, 2004

Exhibit__(MMF-1)
Schedule 4
Page 1 of 1

	(a)	Company Pro Forma Per Books (b)	Company Pro Forma Adjustments (c)	Staff's Pro Forma Adjustments (d)
1	Regulatory Expense	$ 1,869		
	NG04-004 Rate Case Expense			
2	Gaske (Return on Equity)		$ 60,575	$ 9,500
3	Towers Perrin (SISP)		$ 78,170	
4	Gerdes (Legal)		$ 24,000	$ 711
5	MDU Staff (Hearing expense)		$ 5,795	
6	PUC		$ 150,000	$ 69,521
8	Other		$ 5,700	
	Total NG04-004 Expense		$ 324,240	$ 79,732
9	NG02-011 Remaining Unamortized		$ 142,704	$ 116,231
	Total to be amortized		$ 466,944	$ 195,963
10	Three year amortization		$ 155,648	
11	Staff Adjustment (Five year amortization)			$ 39,193
12	Recurring Regulatory Expense		$ 658	$ 658
13	Test year per books regulatory expense		$ (1,869)	$ (1,869)
14	Company Pro Forma Rate Case Expense		$ 154,437	
15	Staff Pro Forma Adjustment			$ 37,982

Sources:

Column b, Lines 1: Statement H, Schedule H-1, Page 17 of 21
Column c, Lines 2 - 8, and 9: Response No. 1-4 Attachment A, Statement H, Page 83
Column c and d, Line 12: Response No. 1-4 Attachment A, Statement H, Page 83
3 year average of company regulatory expense,
Column d, Line 1: Company expenses through 9-30-04
Column d, Line 6: Staff expenses through 9-30-04 plus consultant contract amount

RECEIVED
OCT 15 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Montana-Dakota Utilities Co.
Application to Increase Gas Rates in South Dakota
Docket No. NG04-004

Testimony
Of
Basil L. Copeland Jr.
On Behalf of the Commission Staff

October 2004

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Montana-Dakota Utilities Co.
Application to Increase Gas Rates in South Dakota
Docket No. NG04-004

Testimony
Of
Basil L. Copeland Jr.
On Behalf of the Commission Staff

October 2004

I. BACKGROUND AND QUALIFICATIONS

Formatted

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Basil L. Copeland Jr. and my business address is 14619 Corvallis Road, Maumelle, AR, 72113.

Q. WHAT IS YOUR OCCUPATION, BY WHOM ARE YOU EMPLOYED, AND FOR WHOM ARE YOU TESTIFYING?

A. I am an economist, specializing in energy and utility economics, and a principal in Chesapeake Regulatory Consultants, Inc., Clarksville, MD. I am testifying on behalf of the Staff of the South Dakota Public Utilities Commission.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received my education at Portland State College (1967-1969), New Mexico Institute of Mining and Technology (1969), and Oregon State University (1972-75). In 1974 I received a Bachelor of Science degree in Economics from Oregon State University, and in 1976 a Master of Science degree in Resource Economics (with a minor in Business Finance) from the same institution.

From August 1975 to February 1977, I worked as a financial analyst and staff economist for the Arkansas Public Service Commission. From March 1977 to August 1978, I worked in a similar position with the Iowa State Commerce Commission. In September of 1978 I went to work for the Attorney General of Arkansas in a U.S. Department of Energy-funded office of consumer services, with responsibility for economic analysis in electric utility rate cases. While with the Attorney General, I assisted in the development of legislation that created the Arkansas Department of Energy. In July of 1979, soon after the Department was officially created, I became Deputy Director for Forecasting. In that position, I directed a staff with broad responsibilities involving the development of an energy management information system for monitoring energy supply and demand in Arkansas, including comprehensive forecasts of energy demand by fuel source and sector.

I left the Arkansas Department of Energy in January 1981, and worked briefly as an independent consultant before joining the consulting firm of Hess and Lim, Inc., in April 1981. While employed by Hess and Lim, I served as a consultant on numerous rate cases before the FERC and various state utility commissions. I left Hess & Lim in October 1986 to join with two other consultants in the founding of Chesapeake Regulatory Consultants. I have testified or provided technical assistance in over 150 proceedings before the FERC, the FCC, and regulatory bodies in: Alabama, Arizona, Arkansas, California, Colorado, Georgia, Illinois, Iowa, Kansas, Maine, Maryland, Mississippi, Montana, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Dakota, Texas, Vermont, Washington State, West Virginia, and the District of Columbia. On four occasions I

have been invited to appear on the program of the annual conference of Michigan State University's Institute of Public Utilities, and I have served as faculty for the Michigan State-NARUC summer training program for regulatory commission personnel.

I have published numerous articles on a variety of utility issues, including articles or comments in *Land Economics, American Economic Review, Public Utilities Fortnightly, Journal of Business Research, Yale Journal on Regulation, Journal of Portfolio Management, Energy Law Journal,* and the *Financial Analysts Journal.* My 1982 article in the Financial Analysts Journal on the equity risk premium received a Graham and Dodd award from the Financial Analysts Federation. I have also served as an academic referee for two academic journals where I reviewed articles on utility economics and finance. My article in the Spring 1991 issue of the *Energy Law Journal*[1] dealt with the constitutional standards for due process as applied to utility ratemaking under the celebrated Hope case. It offers a comparative analysis and critique of the 1989 Duquesne decision.[2] A list of publications is provided at the end of my testimony.

II. INTRODUCTION

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

[1] "Procedural vs. Substantive Economic Due Process for Public Utilities," with Walter Nixon. ***Energy Law Journal*** 12 No. 1 (Spring 1991): 81-110.
[2] Federal Power Comm'n v. Hope Natural Gas, 320 U.S. 591 (1944); Duquesne Light Co. v. Barasch, 488 U.S. 591 (1989).

A. My testimony presents evidence concerning the cost of capital for Montana-Dakota Utilities ("MDU"), and recommends a fair and reasonable rate of return based upon that evidence. I also review and respond to MDU's presentation of evidence concerning the cost of capital.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COST OF CAPITAL AND YOUR RECOMMENDED RATE OF RETURN.

A. I conclude that the cost of equity capital for MDU is in the range of 8.5 to 9.5 percent. I normally recommend a rate of return at the midpoint of the range. However, based on testimony presented below, I am recommending a rate of return on equity of 9.25 percent. Using my recommended rate of return on equity and the capital structure and senior capital costs of the Company, I recommend an overall rate of return of 8.734 percent. Exhibit __(BLC-1), Schedule 1 presents the details of this calculation.

Q. IN THE LAST MDU CASE, DOCKET NO. NG02-011, YOU RECOMMENDED A RATE OF RETURN ON EQUITY OF 9.75 PERCENT. WHAT HAS CHANGED THAT WOULD LEAD YOU TO RECOMMEND A LOWER RATE OF RETURN AT THIS TIME?

A. The financial data that I examine to develop an estimate of the cost of equity show that the cost of equity has declined since I filed my testimony in the last case in April, 2003. For example, at that time, the dividend yield component of my cost of equity estimates averaged about 4.9 percent. In the evidence presented below, the dividend yield component ranges from about 4.3 percent to 4.6 percent. On

balance, the data show at least a 50 basis point reduction in the cost of equity since the last case.

III. OVERALL RATE OF RETURN AND THE COST OF EQUITY

Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN RATE OF RETURN AND THE COST OF EQUITY.

A. Typically, regulated utilities have utilized three sources of capital to capitalize their utility assets: common stock, preferred stock, and long-term debt. The rate of return for a regulated firm is usually based on its "weighted average cost of capital." This weighted average cost of capital represents the cost of the individual sources of capital weighted by their proportion as represented in the capital structure. The cost of equity, and my recommended return on equity of 9.25 percent, is one component of this overall rate of return.

Q. HOW ARE CAPITAL COSTS MEASURED?

A. The cost of long-term debt can be directly measured from the interest rate (and related costs) on the various issues of debt used to support the capital structure, and is only rarely a direct source of significant controversy in establishing a rate of return for a regulated utility. Similarly, the cost of preferred stock capital can be measured from the fixed dividend (and related issuance costs) of the company's outstanding stock. The cost of common equity, however, cannot be directly measured or estimated. It must be inferred from market-based common stock dividend and price information using one or more cost of equity estimation methodologies.

Q. WHY IS IT IMPORTANT TO BASE THE ALLOWED RATE OF RETURN ON EQUITY ON THE MARKET COST OF EQUITY?

A. Basing the allowed rate of return on equity on the market cost of equity accomplishes two significant and desirable regulatory objectives. First, it fairly balances the competing interests of ratepayers and shareholders. Ratepayers are interested in receiving safe and reliable service at the lowest possible cost. Shareholders are interested in receiving the highest rate of return they can. A rate of return based on the market cost of equity fairly and reasonably balances these competing interests. If the allowed rate of return on equity is significantly below the market cost of equity, the impairment of the firm's financial integrity undermines its ability as an ongoing concern to render safe and reliable service. So it is in the ratepayer's interest to allow a rate of return on equity at least equal to the market cost of equity. Ratepayers, however, have no interest in paying a rate of return significantly above the cost of equity. And while shareholders may delight at the opportunity to earn the excess profits associated with a return on equity above the cost of equity, they should not complain if the allowed equity return is consistently established on the basis of the market cost of equity. Such a return is commensurate with the financial risks they incur, and with the returns they could earn elsewhere in the marketplace on comparable investments.

Second, an allowed rate of return on equity for the Company equal to the market cost of equity provides the appropriate management incentives to operate the firm safely, reliably and efficiently. An allowed rate of return on equity equal to the market cost of equity provides the same kind of incentive to the managers of a

regulated firm as does earnings per share and market value goals for a competitive unregulated firm. If management has a reasonable opportunity to earn a rate of return on equity equal to the market cost of equity, it should be able to meet all reasonable goals and expectations of both shareholders and ratepayers.

IV. MDU'S COST OF EQUITY CAPITAL

Q. WHAT METHOD DID YOU USE TO DETERMINE MDU'S COST OF EQUITY CAPITAL?

A. I used two variations of the "Discounted Cash Flow" ("DCF") methodology. I also performed a supplemental "Capital Asset Pricing Model" ("CAPM") analysis.

Q. PLEASE EXPLAIN THE BASIC PROCEDURES INVOLVED IN USING THE "DISCOUNTED CASH FLOW" METHODOLOGY.

A. In its most basic form, the DCF theory is a "constant growth" model in which the investor's required return on common stock equity equals the dividend yield on the stock plus the expected rate of growth in the dividend. This relationship is commonly represented mathematically as:

$$k = D/P + g$$

where k is the cost of equity capital (the investor's required return), D/P is the dividend yield (the dividend divided by market price), and g is the expected rate of growth in the dividend. Depending on the nature of the assumptions and mathematical procedures employed in the derivation of the model, the dividend yield portion of the total return is variously represented as D_0/P_0 or D_1/P_0 where D_0 and D_1 represent the "current dividend" and the "next period dividend," respectively.

Depending further on what is assumed about the frequency of the dividend payout and the compounding of intra-period retained earnings, as an annual yield D_0/P_0 will tend to understate the effective yield, while D_1/P_0 will tend to overstate it. A valid conceptual argument can be made for using an average of the two, sometimes presented in the form $D_0(1+.5g)/P_0$. This is the form of the constant growth model I used in my initial DCF analysis.

Q. WHAT OTHER STEPS ARE INVOLVED IN IMPLEMENTING THE DCF METHODOLOGY?

A. The principal steps in implementing the DCF approach are the selection of a sample of companies to which to apply the method, and the selection of measures of expected growth. Where possible, I prefer to utilize the same sample of companies that the applicant uses to determine its cost of capital. In this instance, I do not believe that it is proper to rely upon the sample of companies utilized by MDU's witness to estimate the cost of capital to MDU.

Q. PLEASE EXPLAIN WHY NOT.

A. MDU's rate of return witness, J. Stephen Gaske, developed his recommendation using a sample based upon Moody's Natural Gas Distribution Companies. While this docket concerns a requested gas rate increase, the proper rate of return on equity is one which is fair to MDU's shareholders, and not necessarily to a particular segment of the business. The applicable standard under Hope as to what is fair from the investor point of view is that the return be commensurate with what the investors could reasonably expect to earn on investments of comparable risk. Investors cannot invest in just the gas distribution operations of MDU. They must invest in

MDU as a whole. Thus the relevant standard of comparability is to operations comparable to MDU as a whole. In my opinion, this requires that the sample of comparable companies be combination utilities with combined gas and electric operations similar to MDU. For this reason, I have used a sample of 12 utilities with both electric operations and gas distribution operations.

However, I also estimated the cost of equity using the same methodologies described here on Dr. Gaske's sample of natural gas distribution utilities. The results, presented below, show that there is little or no difference in the cost of equity between the two groups at the present time. If anything, my recommendation might have been slightly lower if based solely upon a sample of natural gas distribution companies.

Q. WHAT DATA DID YOU EXAMINE IN ORDER TO ESTIMATE THE INVESTOR EXPECTED GROWTH RATE FOR YOUR DCF ANALYSIS?

A. For my constant growth DCF study, I utilized the Zacks consensus estimate of projected growth in earnings per share ("EPS"), and Value Line estimates of growth in dividends per share ("DPS"), growth in book value per share ("BVPS"), and the Value Line estimate of "% Retained to Common Equity" (a measure of long term sustainable growth).[3] Theoretically, if the constant growth assumptions are valid, earnings, dividends, and book value per share should all grow at approximately the same rate. Where this is the case, it is sometimes possible to derive reasonable and

[3] Zacks and Value Line are sources of financial data widely used by investors. Besides basic financial data, Zacks surveys institutional investors to collect data on expected earnings growth (referred to as "consensus" estimates of expected earnings growth). "% Retained to Common Equity" is a measure of the ratio of retained earnings to common equity, or the "plowback ratio." It is

accurate estimates of the cost of equity using only one of these growth measures as a "proxy" for the expected rate of growth in dividends. But if the payout ratio is not constant, using just projected earnings or dividend growth can result in distorted estimates of the DCF cost of equity.

Q. WHAT ARE YOUR ESTIMATES OF THE PROJECTED GROWTH RATES FOR THESE MEASURES?

A. For my core sample of combination electric and gas utilities, the projected growth rates used in my constant growth DCF study are shown on Exhibit BLC-1, Schedule 2. As can be seen from Columns F and G, there is considerable disparity between the EPS growth rates projected by Zacks and the DPS growth rates projected by Value Line. The projected EPS growth rates are on average substantially higher than the DPS growth rates. This disparity reflects a projected near-term decline in dividend payout, resulting in a rise in the earnings retention rate. But the constant growth DCF model is a model of investors' long-term dividend growth expectations. Consequently, based on current market conditions, relying solely upon projected EPS growth rates will overstate the investors' long-term growth expectations. Similarly, relying solely upon projected DPS growth rates will understate the investors' long-term growth expectations.

Q. UNDER THESE CONDITIONS, WHAT IS THE BEST WAY TO ESTIMATE THE CONSTANT GROWTH DCF COST OF EQUITY?

A. Under these conditions, the best way to estimate the constant growth DCF cost of equity is to rely upon an average of the EPS, DPS, and book value per share (BVPS)

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equivalent to the "br" measure of expected dividend growth used in some presentations of the DCF

projections. Short-run or near-term changes in payout ratio do not impact book value per share growth as significantly as they do EPS and DPS growth, and over time EPS and DPS growth rates will always revert to the rate of growth in book value per share.[4] For this reason, an average of these various growth rate measures is required to reasonably estimate investors' long-term growth expectations.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR CONSTANT GROWTH DCF STUDY.

A. For the sample of combination utilities, the results are shown on Exhibit BLC-1, Schedule 2, Column L. Column L is the sum of Column E and the average of Columns F, G, H and I. Column E is the dividend yield portion of the DCF cost of equity, and is computed using a 180-day moving average stock price.[5] By averaging the growth rates in Columns F, G, H and I, we avoid the bias that arises from relying solely upon a single measure of expected growth. The mean estimate of "k" is 8.60 percent, and the median estimate of "k" is 8.58 percent. The difference between the median and the mean reflects the impact of "outliers" or atypical observations in the

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model.

[4] A trend in the payout ratio faces two limits – a payout ratio of 100 percent if the payout ratio is rising, and a payout ratio of zero if the payout ratio is declining. At these limits growth in dividends or earnings becomes equal to the rate of growth in book value per share. If the trend in payout ratio levels off, so that payout ratio stabilizes, growth in dividends and earnings will equal growth in book value per share. So regardless of the trend in payout ratio, growth in dividends and earnings will always, ultimately, revert to growth in book value per share.

[5] However, I compare the 180 day moving average to "Bollinger Bands" around the recent stock price. Bollinger Bands are bands used in charting stock prices, and plot a range of two standard deviations around a 20 day moving average. If the 180 day moving average is outside the Bollinger Band, I use the price indicated by the Bollinger Band in the place of the 180 day moving average. Thus the stock price I use is always within two standard deviations of a 20 day moving average, answering any concern that use of a 180 day moving average represents stale price data.

calculation of the mean. For that reason the median is the more reliable measure of central tendency.

Q. WHAT WERE THE COMPARABLE RESULTS FOR DR. GASKE'S SAMPLE OF GAS DISTRIBUTION UTILITIES?

A. Exhibit____(BLC-1), Schedule 4, is a comparable schedule for Dr. Gaske's sample of natural gas distribution utilities. The mean cost of equity using the same methodology as in Schedule 2 was 8.30 percent, while the median cost of equity was 8.11 percent.

Q. DID YOU UNDERTAKE ANY ADDITIONAL DCF ANALYSIS?

A. Yes, I did. In addition to the more traditional form of the DCF methodology, I developed DCF estimates using a "dividend discount model" (DDM). Dividend discount models are more general forms of the DCF methodology, which embody less restrictive assumptions than the traditional methodology. The traditional methodology is sometimes referred to as the "constant growth model," and assumes that dividends, earnings, book value per share, and share price all grow at the same uniform rate of growth in perpetuity. While this is rarely the case in actuality, it is not an unreasonable assumption if the differences are small, a condition which implicitly requires a relatively constant dividend payout ratio. Where dividend payout ratios are expected to trend upward or downward over extended periods of time, use of five-year growth projections of the type published by Zacks, Value Line, or other investment services in a constant growth form of the DCF model can produce distorted and unreliable results. Multiple-period dividend discount models provide

more reliable and accurate measures of the expected DCF return under such conditions.

Q. PLEASE EXPLAIN IN FURTHER DETAIL HOW THE MULTIPLE PERIOD DIVIDEND DISCOUNT MODEL IS DERIVED.

A. Multiple period dividend discount models are based on finite horizon DCF models of the form:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_t}{(1+k)^t} + \frac{P_t}{(1+k)^t}$$

Where

$$P_t = \frac{D_t(1+g)}{(k-g)}$$

Here t is a finite time period at the end of which the stock would be sold for P_t.. By defining this period of constant growth to terminate at some finite point of time in the future, dividends can be projected during the interim that follow any pattern consistent with expected earnings growth and dividend payout ratios.

Q. ARE SUCH DDM MODELS ACTUALLY USED BY INVESTORS TO ESTIMATE EXPECTED RETURNS?

A. Yes. Firms such as Prudential-Bache and Merrill Lynch have used such models to develop expected returns, which were then used by their investment analysts in making stock buy-hold-sell recommendations. Standard textbooks also present them along with constant growth models.

Q. PLEASE DESCRIBE IN FURTHER DETAIL YOUR IMPLEMENTATION OF THIS METHODOLOGY.

A. The basic data employed in my implementation of this methodology is presented in Exhibit____(BLC-1), Schedule 3. This is a summary sheet with input data and the resulting DDM estimates of the cost of equity. Detailed backup is provided in my workpapers.

The basic input data consists of the current dividend yield, an estimated EPS projection for 2004, the current Zacks consensus EPS growth projection, an estimate of long-term growth into perpetuity, and estimated retention ratios for 2004, 2008, and 2023. The DDM analysis assumes that earnings grow from 2004 to 2008 at the indicated Zacks consensus EPS growth rate, and at the long-term growth rate (4.50 percent, the median value of Value Line's "% Retained to Common Equity") thereafter. The period from 2008 to 2023 is a transition period during which the payout ratio changes from the value projected by Value Line in the year 2008 to a common value of 0.41 (the median Value Line estimate for 2008) for all companies in the sample in the year 2023. Constant growth assumptions — long-term growth 4.50 percent, and a retention ratio of 0.41 percent — apply after the year 2023, allowing the determination of a terminal share price for the year 2023. These long-term conditions after 2023 are applied to all the companies in the sample. Having generated a series of cash flows, the model generates an expected return, *k*, by solving the following equation:

$$0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_t}{(1+k)^t} + \frac{P_t}{(1+k)^t} - P_0$$

The solution to this equation is the value of *k* which makes the right hand side of the equation zero. This can only be done by trial and error. However, there are

generally available computer algorithms for finding the solution to such formulas automatically. The DDM returns shown on Exhibit____(BLC-1), Schedule 3, were developed using the "solver" routine in an Excel spreadsheet.

Q. PLEASE SUMMARIZE THE RESULTS AND COMMENT ON THEIR SIGNIFICANCE.

A. The mean and median DDM returns for the 12 company sample of combination utilities were 8.65 percent and 8.86 percent, respectively. These results corroborate the results of the constant growth analysis.

Q. DID YOU UNDERTAKE A COMPARABLE DDM ANALYSIS FOR DR. GASKE'S SAMPLE OF NATURAL GAS DISTRIBUTION COMPANIES?

A. Yes, I did. The results are shown in Exhibit____(BLC-1), Schedule 5. The mean and median DDM returns for sample of natural gas distribution companies were 8.50 percent and 8.45 percent, respectively.

Q. DID YOU UNDERTAKE A SUPPLEMENTAL ANALYSIS OF THE COST OF EQUITY FOR THE SAMPLE OF COMPARABLE COMPANIES TO VALIDATE YOUR DCF RESULTS?

A. Yes, I did. I used the Capital Asset Pricing Model (CAPM) to develop a third estimate of the cost of equity. CAPM is a risk premium methodology based on the principle that the cost of equity capital equals the cost of a risk-free investment, plus a "risk premium" to compensate investors for the risks associated with a specific equity investment. Under the CAPM methodology, the overall market risk premium for common stock is adjusted to reflect the risk of a specific stock or sample of stocks using the stock's beta coefficient. A beta coefficient is a financial market measure

used in developing a risk-adjusted risk premium that reflects the market risk of an individual stock (sometimes referred to as its "systematic risk") relative to the risk of the market as a whole. This stock-specific risk premium is then added to an appropriate "risk-free" rate to yield a total required rate of return. Mathematically, the CAPM methodology can be stated as:

$$k = r_f + \beta r_p$$

where r_f is the risk-free rate, β is the stock's beta coefficient, and r_p is the market risk premium. For an estimate of the required return on stock, the yield on long-term government bonds is conventionally used to estimate the risk-free rate. More problematic is the estimate of the market risk premium.

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM?

A. I estimated the overall market risk premium using the historical return data shown on Exhibit BLC-1, Schedule 6. These data indicate that for the last 79 years, common stocks have earned a long-horizon risk premium over long-term U.S. Treasury bonds of about 4.24 percent (median) to 5.27 percent (mean), annually. For the beta coefficient, I utilized the Value Line estimates for the sample of combination utilities that I used to develop my DCF estimates.

Q. WHAT IS THE RESULTING CAPM ESTIMATE OF THE COST OF EQUITY?

A. The details are presented in Exhibit____(BLC-1), Schedule 6. Using the mean historical risk premium, the resulting CAPM cost of equity for the sample is 9.07 percent. Using the median historical risk premium, the resulting CAPM cost of equity is 8.28 percent. These results corroborate the reasonableness of my DCF estimates,

and provide additional evidence of a reasonable range for the Company's cost of equity.

Q. CONSIDERING THE EVIDENCE YOU PRESENT, WHAT IS YOUR ESTIMATE OF THE COST OF EQUITY FOR MDU?

A. Based upon the evidence presented above, I conclude that the cost of equity for MDU is presently in the range of 8.5 percent to 9.5 percent.

V. ANALYSIS OF MDU RATE OF RETURN TESTIMONY

Q. HAVE YOU REVIEWED THE TESTIMONY AND EXHIBITS OF J. STEPHEN GASKE, THE WITNESS SPONSORING MDU'S REQUESTED RETURN ON EQUITY?

A. Yes, I have.

Q. PLEASE COMMENT ON THE EVIDENCE SUBMITTED BY DR. GASKE IN SUPPORT OF HIS RATE OF RETURN RECOMMENDATION.

A. Dr. Gaske begins his presentation with the DCF method, which he applies to a sample of natural gas distribution companies. I have already stated why I believe that this is an inappropriate sample for estimating the cost of equity for MDU. So whatever other merit his studies might have, he is not, in my opinion, estimating the cost of equity capital for MDU. But beyond that, I do see significant problems with the way he implements his DCF analyses. His first DCF approach is described as a "Second-Stage Retention Growth" analysis. Superficially, this seems to be an attempt to implement a two-stage dividend discount model similar to the DDM that I describe earlier in my testimony. But it is fundamentally flawed because it relies

solely upon projected earnings growth rates for the initial, near term stage. This is not merely a fundamental flaw, but a fatal one. After all, the "D" in "DCF" represents the dividend cash flow to the investor, and Dr. Gaske has not presented one iota of evidence regarding projected dividend growth. While dividends are arguably paid out of earnings, earnings growth is a reasonable proxy for dividend growth only if the payout ratio is constant, an assumption simply not borne out under current market conditions. Dr. Gaske's second DCF method, described as "a Basic DCF method" merely compounds this flaw, since it relies solely upon near-term earnings forecasts for both the near-term and the long-term. Because Dr. Gaske has made no use of any evidence with respect to investor expectations regarding dividend growth, it is impossible for him to have reliably or accurately implemented the DCF model.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING DR. GASKE'S DCF ANALYSES?

A. Yes, I two additional comments regarding Dr. Gaske's DCF analyses. First, Dr. Gaske utilizes a variation in the quarterly compounding DCF model in which he multiplies the dividend yield by (1 + .625g) where "g" is the growth component of this DCF analysis. Other problems with the quarterly compounding model left aside (which are not at issue in the context of this case), multiplying by "g" will produce a higher effective dividend yield than investors can reasonably expect to receive over the next 12 months because dividends are growing much more slowly than the "g" used in Dr. Gaske's analysis. For example, for some of companies in Dr. Gaske's sample, investment analysts are not projecting any dividend growth for the next year (e.g., Keyspan, NICOR, and WGL Holdings). In all cases the projected dividend

growth for the next twelve months is substantially lower than what is imputed with Dr. Gaske's "g" value, which is based on projected earnings growth.

Q. WHAT IS THE OTHER COMMENT YOU HAVE REGARDING DR. GASKE'S DCF ANALYSES?

A. Dr. Gaske makes a "flotation cost adjustment" in which he multiplies the DCF cost of equity by (1 + 0.0475). The "0.0475" reflects an estimate of flotation cost as a percentage of issuance price. I don't have a problem with the reasonableness of this as an estimate of flotation cost. The problem is that he multiplies it against the entire DCF rate of return when it should only be multiplied against the dividend yield portion of the return. Since his DCF estimates are generally in the range of 9 to 10 percent before he makes this adjustment, whereas the dividend yields are only about 4 to 5 percent, he effectively doubles the allowance for flotation costs.

Q. IN YOUR OPINION, WHAT WOULD BE A REASONABLE ALLOWANCE FOR FLOTATION COST UNDER PRESENT CONDITIONS?

A. With dividend yields of 4 to 5 percent, and a flotation cost allowance of 5 percent, a reasonable flotation cost adjustment under present conditions would be on the order of 20 to 25 basis points. My recommended ROE of 9.25 percent is 25 basis points above the midpoint of my cost of equity range of 8.5 to 9.5 percent. This is more than adequate to cover flotation costs under present conditions.

Q. PLEASE DISCUSS DR. GASKE'S RISK PREMIUM APPROACHES.

A. Dr. Gaske employs two risk premium approaches which share a common weakness: utilization of simple arithmetic averages to estimate the historical risk premium. The

correct approach will make use of geometric averages for appropriate long-horizon holding periods.[6]

Q. DR. GASKE ALSO DISCUSSES THE RETURNS ON ALTERNATIVE EQUITY INVESTMENTS. PLEASE COMMENT.

A. The evidence that Dr. Gaske presents regarding "alternative equity investments" is of no value whatsoever to determining the fair rate of return and cost of equity for MDU. First of all, the data that he presents represents returns on book equity. Investors cannot purchase stock at book value (unless the market-to-book ratio is 1.0); they must purchase stock at market value. Hence, investors do not have the opportunity to earn these book returns. They only have the opportunity to earn the equilibrium market return. That is why commissions and regulatory agencies long ago discarded the "comparable earnings" approach and adopted the DCF approach. While he declines to describe it as such, Dr. Gaske's "alternative equity investment analysis" is nothing more than a "comparable earnings" analysis under the guise of a different name. But it is still just as flawed.

Secondly, these are not the returns on investments of comparable risk. The measures that Dr. Gaske employs – 746 industrial, retail, and transportations published by Value Line – is too broad to represent the return on investments of comparable risk. Hence there is no way that this evidence can be helpful in determining a reasonable rate of return for MDU.

Q. PLEASE SUMMARIZE YOUR COMMENTS ON DR. GASKE'S TESTIMONY.

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[6]See Russell J. Fuller and Kent A. Hickman, "A Note on Estimating the Historical Risk Premium," Financial Practice and Education, Fall/Winter 1991, Vol 1., No. 2, 45-48.

A. In my opinion, Dr. Gaske has failed to present any meaningful evidence of the cost of equity or fair rate of return on equity for MDU.

Q. DOES THAT COMPLETE YOUR TESTIMONY AT THE PRESENT TIME?

A. Yes, it does, except for the list of publications that follows.

Publications
of
Basil L. Copeland, Jr.

"Double Leverage One More Time." ***Public Utilities Fortnightly***, August 18, 1977, 19-24.

"Alternative Cost of Capital Concepts In Regulation." ***Land Economics*** 54 (August 1978): 348-61.

"Estimates of the Cost of Equity for Public Utilities, 1971-1976." ***Journal of Business Research*** 7 No. 1 (1979): 9-17.

"The Cost of Equity Capital: A Model for Regulatory Review." In **Issues in Public Utility Regulation**, edited by Harry M. Trebing, 342-66. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1979.

"Capacity Planning, Reliability, and Outage Costs in Electricity Supply: Comments." In **Challenges for Public Utility Regulation in the 1980's**, edited by Harry M. Trebing, 511-516. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1981.

"Inflation, Interest Rates, and Equity Risk Premia." ***Financial Analysts Journal*** (May/June 1982): 32-43.

"Do Stock Prices Move Too Much to be Justified by Subsequent Changes in Dividends? Comment." ***American Economic Review*** 73 No. 1 (1983): 234-35.

"Inflation, Monetary Policy, and the Equity Risk Premium." In **Regulatory Reform: The State of the Regulatory Art, Emerging Concepts and Procedures** edited by J. Rhoads Foster, 183-201. Washington: Institute for Study of Regulation, 1984.

"Ratemaking Treatment of Excess Capacity: Reconciling Regulation with Consumer Sovereignty." In **Changing Patterns in Regulation, Markets, and Technology: The Effect on Public Utility Pricing** edited by Patrick C. Mann and Harry M. Trebing, 407-40. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1984.

"Bailing Out Public Utilities with Troubled Nuclear Power Plants: Who wins, Who Loses?" In **The Impact of Deregulation and Market Forces on Public Utilities: The Future Role of Regulation** edited by Patrick C. Mann and Harry M. Trebing, 371-91. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1985.

"Price Theory and Telecommunications Regulation: A Dissenting View," with A. Severn. ***Yale Journal on Regulation*** 3 No. 1 (Fall 1985): 53-85.

"Capital Gains Taxes After Tax Reform," with Alan K. Severn. ***Journal of Portfolio Management*** 13 No. 3 (Spring 1987): 69-75.

"Escape from the Black Hole of FERC: A Proposal to Restore ***Pike*** Prudence Review," with Robert E. Johnston. ***The Electricity Journal*** 2 No. 4 (May 1989): 12-25.

"Telecommunications Regulation - The Continuing Dilemma: Commentary." In **Public Utility Regulation, The Economic and Social Control of Industry**, edited by Kenneth Nowotny, David B. Smith, and Harry M. Trebing, 131-36. Boston: Kluwer Academic Publishers, 1989.

"Procedural vs. Substantive Economic Due Process for Public Utilities," with Walter Nixon. ***Energy Law Journal*** 12 No. 1 (Spring 1991): 81-110.

Montana-Dakota Utilities Co.
Cost of Capital at June 30, 2004

Component		Balance as of June 30, 2004	Percent of Total	Cost	Weighted Cost
Long Term Debt		$160,850,000	46.051%	8.596%	3.959%
Preferred Stock		$16,200,000	4.638%	4.620%	0.214%
Common Equity					
Consolidated	$1,557,664,965				
Less:					
Unappropriated Retained Earnings of Subsidiaries	($573,854,463)				
Additional Equity of Subsidiaries	($60,814,000)				
Capital Investment in Subsidiaries	($750,762,563)				
Utility Common Equity		$172,233,939	49.311%	9.250%	4.561%
Total		$349,283,939	100.000%		8.734%

Sources:
Capitalization, Debt and Preferred Stock costs: MDU Response to Staff Request 1-32
Cost of Common Equity: Copeland testimony

Exhibit___(BLC-1)
Schedule 1
Docket No. NG04-004

MONTANA-DAKOTA UTILITIES CO.
DCF Rate of Return Analysis Using Dividend Cash Flow Model (Constant Growth)
Combination Utilities

Company	Dividend 2004	Dividend 2005	Stock Price	Dividend Yield	Proj. EPS Growth (Zacks)	Proj. DPS Growth (VL)	Proj. BVPS Growth (VL)	% Ret. To Com. Eq. (VL)	Proj Payout Ratio 2004	Proj Payout Ratio 2008	DCF Cost of Equity k
A	B	C	D	E	F	G	H	I	J	K	L
Alliant Energy	1.00	1.00	24.50	4.08%	5.00%	3.78%	3.80%	3.50%	52.63%	56.59%	8.10%
Ameren Corp	2.54	2.54	44.50	5.71%	3.00%	0.00%	2.12%	1.50%	89.12%	83.28%	7.36%
Avista Corp	0.52	0.54	17.50	3.03%	5.00%	7.71%	4.99%	4.50%	52.00%	46.67%	8.58%
Cinergy Corp.	1.88	1.92	38.00	5.00%	4.00%	2.06%	4.47%	3.50%	70.94%	68.00%	8.51%
DTE Energy	2.06	2.06	40.00	5.15%	5.00%	0.48%	4.29%	4.50%	68.67%	56.00%	8.72%
NISOURCE	0.92	0.94	21.00	4.43%	5.00%	4.57%	4.65%	4.50%	57.50%	55.00%	9.11%
OGE Energy	1.33	1.33	24.50	5.43%	3.00%	1.29%	2.76%	3.50%	80.61%	70.00%	8.07%
Puget Energy Inc.	1.00	1.00	22.00	4.55%	5.00%	2.87%	3.74%	3.50%	80.00%	64.00%	8.32%
Sempra Energy	1.00	1.00	33.00	3.03%	6.00%	0.00%	11.98%	9.00%	33.33%	26.67%	9.77%
Vectran	1.15	1.19	24.50	4.78%	6.00%	3.31%	3.56%	4.50%	67.65%	62.38%	9.12%
Wisconsin Energy	0.83	0.87	32.00	2.66%	7.00%	4.77%	7.03%	6.50%	38.60%	36.36%	8.98%
WPS Resources	2.20	2.24	46.00	4.83%	4.00%	1.77%	4.50%	4.00%	62.86%	64.66%	8.39%
			Mean:	**4.39%**	**4.83%**	**2.80%**	**4.82%**	**4.42%**	**62.83%**	**57.47%**	**8.60%**
			Median:	**4.55%**	**5.00%**	**2.87%**	**4.29%**	**4.50%**	**67.65%**	**56.59%**	**8.58%**
				Std Error:	**0.36%**	**0.69%**	**0.77%**	**0.56%**			**0.19%**

Sources

Columns B, C and I: Value Line
Column D: SiliconInvestor.Com
Column F: Zacks Investment Research
Column E: ((Column B + Column C) / 2) / Column D
Columns G, H, J and K: Computed from Value Line data
Column L: Column E plus the average of Columns F through I

Exhibit____(BLC-1)
Schedule 2
Docket No. NG04-004

Exhibit____(BLC-1)
Schedule 3
Docket No. NG04-004

MONTANA-DAKOTA UTILITIES CO.
DCF Rate of Return Analysis Using Dividend Discount Model (DDM)
Combination Utilities

Company	Inputs:							Output:
	Dividend Yield	2004 EPS	Zacks Growth	Long-Term Growth	Retention Ratios 2004	2008	2023	DDM Return
Alliant Energy	4.08%	1.90	5.00%	4.50%	0.47	0.43	0.41	8.99%
Ameren Corp	5.71%	2.85	3.00%	4.50%	0.11	0.17	0.41	8.60%
Avista Corp	3.03%	1.00	5.00%	4.50%	0.48	0.53	0.41	7.74%
Cinergy Corp.	5.00%	2.65	4.00%	4.50%	0.29	0.32	0.41	8.78%
DTE Energy	5.15%	3.00	5.00%	4.50%	0.31	0.44	0.41	8.95%
NISOURCE	4.43%	1.60	5.00%	4.50%	0.43	0.45	0.41	8.96%
OGE Energy	5.43%	1.65	3.00%	4.50%	0.19	0.30	0.41	8.53%
Puget Energy Inc.	4.55%	1.25	5.00%	4.50%	0.20	0.36	0.41	8.02%
Sempra Energy	3.03%	3.00	6.00%	4.50%	0.67	0.73	0.41	8.95%
Vectran	4.78%	1.70	6.00%	4.50%	0.32	0.38	0.41	8.96%
Wisconsin Energy	2.66%	2.15	7.00%	4.50%	0.61	0.64	0.41	8.30%
WPS Resources	4.83%	3.50	4.00%	4.50%	0.37	0.35	0.41	9.05%
Mean:	**4.39%**		**4.83%**	**4.50%**	**0.37**	**0.43**		**8.65%**
Median:	**4.55%**		**5.00%**		**0.35**	**0.41**		**8.86%**
Std Error:								**0.10%**

MONTANA-DAKOTA UTILITIES CO.
DCF Rate of Return Analysis Using Dividend Cash Flow Model (Constant Growth)
Natural Gas Distribution Utilities

Company	Dividend 2004	Dividend 2005	Stock Price	Dividend Yield	Proj. EPS Growth (Zacks)	Proj. DPS Growth (VL)	Proj. BVPS Growth (VL)	% Ret. To Com. Eq. (VL)	Proj Payout Ratio 2004	Proj Payout Ratio 2008	DCF Cost of Equity k
A	B	C	D	E	F	G	H	I	J	K	L
AGL Resources	1.15	1.16	29.00	3.98%	5.00%	0.22%	6.43%	6.00%	54.76%	49.36%	8.39%
Atmos Energy	1.22	1.24	25.00	4.92%	4.00%	2.56%	5.45%	3.50%	78.71%	65.85%	8.80%
Energen Corp	0.75	0.77	44.00	1.73%	7.00%	2.57%	2.53%	13.00%	22.73%	21.56%	8.00%
KeySpan Corp	1.78	1.78	34.00	5.24%	5.00%	1.64%	5.06%	5.00%	64.73%	55.07%	9.41%
NICOR	1.86	1.86	36.00	5.17%	4.00%	1.83%	2.08%	3.00%	86.51%	80.00%	7.90%
Northwest Nat Gas	1.30	1.33	30.00	4.38%	4.00%	2.77%	3.28%	4.00%	65.00%	60.42%	7.90%
Piedmont Nat Gas	1.72	1.78	41.00	4.27%	4.00%	2.52%	5.26%	4.00%	70.20%	62.30%	8.21%
South Jersey Inds	1.62	1.67	42.00	3.92%	5.00%	2.24%	2.36%	6.00%	56.84%	52.06%	7.82%
WGL Holdings	1.30	1.30	28.00	4.64%	4.00%	0.76%	3.60%	3.50%	68.42%	62.33%	7.61%
			Mean:	**4.25%**	**4.67%**	**2.04%**	**4.00%**	**5.33%**	**63.10%**	**56.55%**	**8.30%**
			Median:	**4.33%**	**4.50%**	**2.38%**	**4.17%**	**4.50%**	**64.86%**	**57.74%**	**8.11%**
				Std Error:	**0.30%**	**0.27%**	**0.48%**	**0.93%**			**0.17%**

Sources
- Columns B, C and I: Value Line
- Column D: SiliconInvestor.Com
- Column F: Zacks Investment Research
- Column E: ((Column B + Column C) / 2) / Column D
- Columns G, H, J and K: Computed from Value Line data
- Column L: Column E plus the average of Columns F through I

Exhibit___(BLC-1)
Schedule 4
Docket No. NG04-004

MONTANA-DAKOTA UTILITIES CO.
DCF Rate of Return Analysis Using Dividend Discount Model (DDM)
Natural Gas Distribution Utilities

Company	Inputs:							Output:
	Dividend Yield	2004 EPS	Zacks Growth	Long-Term Growth	Retention Ratios 2004	2008	2021	DDM Return
AGL Resources	3.98%	2.10	5.00%	4.50%	0.45	0.51	0.40	8.62%
Atmos Energy	4.92%	1.55	4.00%	4.50%	0.21	0.34	0.40	8.32%
Energen Corp	1.73%	3.30	7.00%	4.50%	0.77	0.78	0.40	8.32%
KeySpan Corp	5.24%	2.75	5.00%	4.50%	0.35	0.45	0.40	9.29%
NICOR	5.17%	2.15	4.00%	4.50%	0.13	0.20	0.40	8.41%
Northwest Nat Gas	4.38%	2.00	4.00%	4.50%	0.35	0.40	0.40	8.45%
Peoples Energy	4.27%	2.45	4.00%	4.50%	0.30	0.38	0.40	8.11%
Southwest Gas	3.92%	2.85	5.00%	4.50%	0.43	0.48	0.40	8.47%
WGL Holdings	4.64%	1.90	4.00%	4.50%	0.32	0.38	0.40	8.53%
Mean:	**4.25%**			**4.50%**	**0.37**	**0.43**		**8.50%**
Median:	**4.33%**				**0.35**	**0.40**		**8.45%**
Std Error:								**0.08%**

Exhibit____(BLC-1)
Schedule 6
Docket No. NG04-004

MONTANA-DAKOTA UTILITIES CO.
CAPM Cost of Equity Analysis
Combination Utilities

Compound Excess Returns (Long Horizon Risk Premia), 1926-2003

Period	Risk Premium
A	B
1925-1940	0.82%
1940-1955	14.38%
1955-1971	4.24%
1971-1987	1.33%
1987-2003	5.58%
Mean:	**5.27%**
Median:	**4.24%**

Source: Derived from SBBI, Valuation Edition, 2004.

CAPM Cost of Equity Analysis:

Company	Stock Beta	R_f	CAPM Cost of Equity w/Mean RP	CAPM Cost of Equity w/Median RP
A	B	C	D	E
Alliant Energy	0.80	5.10%	9.32%	8.49%
Ameren Corp	0.70	5.10%	8.79%	8.07%
Avista Corp	0.85	5.10%	9.58%	8.70%
Cinergy Corp.	0.80	5.10%	9.32%	8.49%
DTE Energy	0.65	5.10%	8.52%	7.86%
NISOURCE	0.75	5.10%	9.05%	8.28%
OGE Energy	0.65	5.10%	8.52%	7.86%
Puget Energy Inc.	0.75	5.10%	9.05%	8.28%
Sempra Energy	0.90	5.10%	9.84%	8.92%
Vectran	0.75	5.10%	9.05%	8.28%
Wisconsin Energy	0.70	5.10%	8.79%	8.07%
WPS Resources	0.75	5.10%	9.05%	8.28%
Mean:	0.74		9.07%	
Median:	0.75			8.28%

Exhibit____(BLC-1)

MONTANA-DAKOTA UTILITIES CO.

Schedule 7

CAPM Cost of Equity Analysis

Docket No. NG04-004

Natural Gas Distribution Utilities

Compound Excess Returns (Long Horizon Risk Premia), 1926-2003

Period	Risk Premium
A	B
1925-1940	0.82%
1940-1955	14.38%
1955-1971	4.24%
1971-1987	1.33%
1987-2003	5.58%
Mean:	**5.27%**
Median:	**4.24%**

Source: Derived from SBBI, Valuation Edition, 2004.

CAPM Cost of Equity Analysis:

Company	Stock Beta	R_f	CAPM Cost of Equity w/Mean RP	CAPM Cost of Equity w/Median RP
A	B	C	D	E
AGL Resources	0.80	5.10%	9.32%	8.49%
Atmos Energy	0.65	5.10%	8.52%	7.86%
Energen Corp	0.70	5.10%	8.79%	8.07%
KeySpan Corp	0.75	5.10%	9.05%	8.28%
NICOR	1.00	5.10%	10.37%	9.34%
Northwest Nat Gas	0.65	5.10%	8.52%	7.86%
Piedmont Natural Gas	0.75	5.10%	9.05%	8.28%
South Jersey Industries	0.55	5.10%	8.00%	7.43%
WGL Holdings	0.75	5.10%	9.05%	8.28%
Mean:	0.73		8.96%	
Median:	0.75			8.28%

RECEIVED
OCT 18 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA- DAKOTA UTILITIES
DOCKET NO. NG04-004

TESTIMONY & EXHIBITS OF MARTIN C. BETTMANN

ON BEHALF OF THE COMMISSION STAFF

OCTOBER 2004

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES
DOCKET NO. NG04-004

TESTIMONY & EXHIBITS OF MARTIN C. BETTMANN
ON BEHALF OF THE COMMISSION STAFF
OCTOBER 2004

Q. What is your name and by whom are you employed?

A. My name is Martin C. Bettmann and I am employed as a Staff Engineer by the South Dakota Public Utilities Commission (Commission). My business address is South Dakota Public Utilities Commission, 500 East Capitol Avenue, Pierre, South Dakota, 57501-5070.

Q. Please describe your education and work experience.

A. I received my Bachelor of Science degree in Engineering from South Dakota State University in 1975. After graduation I was employed by an engineering consulting firm in Aberdeen, South Dakota, prior to taking my present position as a Staff Engineer with the Commission in November 1977.

Q. Please describe what your job involves?

A. Currently, my primary responsibility with the Commission Staff (Staff) is managing the pipeline safety inspection program. While working for the Commission, I have also been responsible for reviewing energy conversion and transmission facility siting applications, evaluating and making recommendations on electric and natural gas rates and tariffs,

and advising the Staff on various engineering and technical matters that come before the Commission.

Q. Have you previously filed testimony in other electric or natural gas rate proceedings before the Commission?

A. Yes, I provided prefiled testimony on behalf of the Staff in four electric and five natural gas rate cases.
In previous rate cases, my written testimony has addressed fuel oil usage at combustion turbine and internal combustion electric generating plants, steam production plant depreciation proposals, the apportionment of revenue responsibility among the customer classes and the rate design proposals, the level of natural gas sales to a power plant, the purchased gas cost reflected in that utilities' operations & maintenance expense, weather normalization, and rate design.

Q. Are you familiar with Montana-Dakota Utilities Company's (Company) application for an increase in revenues?

A. Yes, I have reviewed the direct testimony of the Company witnesses, their exhibits and the responses to Staff data requests pertinent to the preparation of my testimony and exhibits.

Q. What is the purpose of this testimony?

A. For this filing, I am responsible for the review and analysis of the Company's proposed adjustments to Weather Normalization. My testimony also summarizes Staff's proposed rate design.

Q. Have you calculated the weather normal adjustments for the various rate classes?

A. Yes I have. The calculations for the weather normalization adjustments are shown in Exhibit____(MCB-1) through Exhibit____(MCB-4).

Q. How are the weather normal adjustments you made different from those proposed by the Company?

A. My weather normal adjustments are different in several respects. First of all, I have used heating degree day (HDD) values based on a 65-degree day basis instead of the 60-degree day basis used by the Company. The 65 degree day basis was used because it is generally accepted as the temperature level where a building requires heating if the outside temperature drops below that point.

My analysis is different also in the fact that I use a three-month average to determine the base load use instead of just the use from the month in which the customers have the lowest average use. I also then do not calculate a weather normalization adjustment for the three months that are a part of the lowest three-month average. Generally these months contain very few normal HDD's and even a slight variation in the weather can cause a significant adjustment in the weather normalization calculation.
Also, since energy use for the previous month for Ellsworth Air Force Base and the Rate 81 Small Interruptible Transportation customers are reported on the 1st of the following month, it was necessary to use the actual and normal HDD's from the preceding month to determine the weather normalization factor for the month that the sale was reported. For example: the 226, 413 Dekatherms booked as a sale in January 2003 for Ellsworth Air Force Base was actually used in December 2002, therefore the actual and normal HDD values used to determine the "January 2003" weather normalization adjustment were from the month of December 2002.

Q. In your opinion, what should be the amount of the weather normalization adjustment?

A. The weather normalization adjustments for billed and unbilled volumes have not been set out as a separate adjustment but have been included in Staff's rate design comparison Exhibit ___(MCB-5) Schedules 2, 3 and 4. A summary of the weather normal adjustments may also be found in Staff Exhibit___(MCB-1) Schedules 1 and 2.

Q. **How are the revenue increase calculations you performed in Exhibit___(MCB-4) different from the Company's calculations as found in the exhibits of Company?**

A. The obvious difference between the two methods is in the way they are shown on the spreadsheets. The other difference in the two analysis is the incorporation of Staff's weather normalization and revenue deficiencies by customer class to adjust the "per books" billing determinants to calculate an adjusted test year revenue. I then plug in the proposed service charges and increase or decrease the Non-Gas Commodity rate per therm until the target revenue adjustment is achieved.

Q. **What rate design changes does the Company propose for Residential customers?**

A. The Company is not proposing any rate design changes for its Residential customers. The Company is proposing to increase the daily residential customer charge from $0.25 to $0.26. This would increase the average monthly Basic Service Charge by $0.31 to $7.91.

Q. **What rate design changes does the Staff propose for Residential customers?**

A. Staff is proposing to keep the basic rate design structure. It is my opinion that the Basic Service Charge for the Residential customers should not be changed as recommended by Staff Witness Towers. The $87,161 portion of the overall increase that Staff Witness Towers has recommended for the residential class would be recovered through an increase in the Distribution Delivery Charge. I have calculated that rate to be $1.46372.

Q. **What rate design changes does the Company propose for Small and Large Meter Firm General Service customer classes?**

A. As with the Residential class, the Company is not proposing any changes in the design of the rates for the Small and Large Meter Firm General Service classes. The Company is proposing to increase the Basic Service Charge for Small Meter customers by $0.02 per day to $0.35 per day or by an average of $0.61 to $10.65 per month. The increase in

the Basic Service Charge for the Large Meter Firm customers would be $0.04 per day or on average $1.21 per month to $21.29.

Q. **What rate design changes does the Staff propose for Small and Large Meter Firm General Service customers?**

A. Staff is proposing to keep the current basic rate design structure for both the Small and Large Meter General Service customer classes. Staff Witness Towers has testified that $116,509 of the entire rate increase recommended by Staff be assigned to the Firm General service class. Based on that recommendation and the Customer Cost analysis in Staff Witness Towers' Exhibit No.___(RGT-4), it is my opinion that the Basic Service Charge for Small Meter Firm General Service customers should be increased as proposed by the Company to $0.35 per day for the Small Meter Firm customers and $0.70 per day for the Large Meter Firm customers. The balance of theincrease would be recovered by increasing the Distribution Delivery Charge to $1.11250 per dekatherm. My calculations in Exhibit___(MCB-5) shows that the rates proposed will generate the additional revenue requirement allocated to the Firm General Service customer class.

Q. Are you recommending any changes to the Optional Seasonal General Gas Service Rate 72?

A. It is my opinion that the current rate design should be retained and the Non-Gas Commodity Charge should be set at the same levels as that of the Firm General Gas Service rate. The Base Rate should also remain at the same levels as the Small and Large Meter Firm customers in Rate 71.

Q. What changes are proposed for Ellsworth Air Force Base and the other Interruptible and Transportation customer classes?

A. The following table shows the current tariffed rates and both the Company and Staff proposed rates for these customers.

Ellsworth Air Force Base Rate 64	
Base Rate	Interruptible Sales Non-Gas Commodity Charge
Current Rate	
$95.00 per month	$0.062 per dk
Proposed Rate by Company;	
$95.00 per month	$0.062 per dk
Proposed Rate by Staff:	
$95.00 per month	$0.062 per dk

Small Interruptible General Gas Service Rate 71		
Base Rate	Commodity Charge Max. Rate Per Dk	Commodity Charge Min. Rate Per Dk
Current Rate;		
$50.00 per month	$0.453 per dk	$0.131 per dk
Proposed Rate by Company;		
$50.00 per month	$0.453 per dk	$0.131 per dk
Proposed Rate by Staff:		
$50.00 per month	$0.453 per dk	$0.131 per dk

Large Interruptible General Gas Service Rate 85		
Base Rate	Commodity Charge Max. Rate Per Dk	Commodity Charge Min. Rate Per Dk
Current Rate;		
$150.00 per month	$0.177 per dk	$0.090 per dk
Proposed Rate by Company;		
$175.00 per month	$0.183 per dk	$0.090 per dk
Proposed Rate by Staff:		
$175.00 per month	$0.18192 per dk	$0.090 per dk

Small Interruptible General Gas Transportation Service Rate 81			
Base Rate	Commodity Charge Max. Rate Per Dk	Commodity Charge Min. Rate Per Dk	Balancing Charge per Dk
Current Rate;			
$125.00	$0.453 per dk	$0.131 per dk	$0.300 per dk
Proposed Rate by Company;			

$125.00	$0.453 per dk	$0.131 per dk	$0.300 per dk
Proposed Rate by Staff:			
$125.00	$0.45549 per dk	$0.131 per dk	$0.300 per dk
Large Interruptible General Gas Transportation Service Rate 82			
Base Rate	Commodity Charge Max. Rate Per Dk	Commodity Charge Min. Rate Per Dk	Balancing Charge per Dk
Current Rate;			
$200.00	$0.177 per dk	$0.090 per dk	$0.300 per dk
Proposed Rate by Company;			
$225.00	$0.183 per dk	$0.090 per dk	$0.300 per dk
Proposed Rate by Staff:			
$225.00	$0.18192 per dk	$0.090 per dk	$0.300 per dk

It is Staff Witness Towers' opinion that the revenue requirement for the Small and Large Interruptible customer classes be increased by $942.00 and $5,831.00 respectively. It is recommendation that the Base Rate be increased by $25.00 for both classes. The Distribution Delivery Charge has been adjusted from $0.45300 to $0.45549 per Dekatherm to recover the balance of the recommended increase in revenues for the Small Interruptible class. Similarly, an increase in the Distribution Delivery Charge from $0.17700 to $0.18192 per Dekatherm is recommend for the Large Interruptible class to recover the balance of the revenue increase proposed by Staff Witness Towers.

Q. In Exhibit (MCB-5) Schedule 3 and Schedule 4 you show adjustments for customers that were reclassified and cut out of service. Please explain those adjustments.

A. A reclassified customer is a customer that was switched from receiving service under one rate to another. In this instance a Small Interruptible (Rate 71) customer was switched to Rate 70, the Firm General Service rate and a Large Interruptible Transportation (Rate 82) customer was reclassified as a Small Interruptible (Rate 81) customer.

Adjustments have also been made to the Small Interruptible General Gas Transportation rate because of customers being cut out of service in Rate 81 and Rate 82.

Q. Have you prepared a bill comparison using the current rates and Staff's proposed rate design?

A. Yes, I have. In Exhibit____(MCB-6) I compare typical bills using the current rates with Staff's proposed rates for the Residential and Firm Commercial customers. I did not calculate typical bills for the Contract, Interruptible and Transportation customers. However, Exhibit____(MCB-7) does show the overall percent increase for the Interruptible and Transportation customer classes. The rates for the Contract customers did not change, but are shown in the same exhibit.

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

A. Yes.

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

NORMAILIZED UNBILLED DEKATHERMS
SOUTH DAKOTA
TEST YEAR ENDED DECEMBER 31, 2003

LINE NO.	RATE CLASS (A)		NORMALIZED UNBILLED DEKATHERM'S (B)
1	RESIDENTIALUNBILLED SALES	DEC-02	(278,834)
2	RESIDENTIALUNBILLED SALES	DEC-03	212,275
			(66,559)
3	SMALL METER FIRM UNBILLED SALES	DEC-02	(49,461)
4	SMALL METER FIRM UNBILLED SALES	DEC-03	35,574
			(13,887)
5	LARGE METER FIRM UNBILLED SALES	DEC-02	(130,886)
6	LARGE METER FIRM UNBILLED SALES	DEC-03	101,443
			(29,443)
7	SMALL INTERRUPTIBLE	DEC-02	(8,603)
8	SMALL INTERRUPTIBLE	DEC-03	5,828
			(2,774)
9	TOTAL UNBILLED SALES		**(112,664)**

Sources:

Column (B): Exhibit ___ (MCB-1) Schedules 6-2 Column (I)

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

SOUTH DAKOTA
BILLLED SALES

LINE NO.	RATE CLASS (A)	DEKATHERM ADJUSTMENT (B)
1	RESIDENTIAL	53,947
2	SMALL METER FIRM GENERAL	7,985
3	LARGE METER FIRM GENERAL	20,950
4	SMALL INTERRUPTIBLE	531
5	SMALL INTERRUPTIBLE TRANSPORTATION	6,226
6	ELLSWORTH AIR FORCE BASE	12,768
7	RATE 702 - FIRM GENERAL	1,954
8	LARGE INTERRUPTIBLE TRANSPORTATION SERVICE	1,079
9	**TOTAL**	**105,441**

Sources:
Column (B) Lines 1-4, and 6-7: Exhibit____(MCB-1) Schedule 6-1 Column (L)
Column (B) Line 5: Exhibit____(MCB-3) Schedule 1-1 Column (L)
Column (B) Line 8: Exhibit____(MCB-4) Schedule 1-1 Column (L)

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

LINE NO.	FIRM GENERAL SERVICE - LARGE METERS CUSTOMERS (K)	DEKATHERM SALES (L)	AVG USE 3 MONTH ENDING (M)	AIR FORCE BASE CUSTOMERS (N)	DEKATHERM SALES (O)	AVG USE 3 MONTH ENDING (P)	RATE 702 - FIRM GENERAL SERVICE CUSTOMERS (Q)	DEKATHERM SALES (R)	AVG USE 3 MONTH ENDING (S)
1	N/A	N/A		N/A	N/A		N/A	N/A	
2	1,324	226,413	143.4116	1	79,083	61,243.6667	1	51,632	57,208.2667
3	1,322	228,615	165.2374	1	89,581	81,664.3333	1	56,802	58,532.8000
4	1,321	229,413	172.5337	1	82,805	83,823.0000	1	68,296	58,909.8000
5	1,319	143,056	151.7123	1	75,725	82,703.6667	1	68,952	64,683.0000
6	1,321	101,798	119.7342	1	44,474	67,668.0000	1	54,249	63,832.1667
7	1,319	73,973	80.5322	1	27,866	49,355.0000	1	50,964	58,054.9333
8	1,318	55,153	58.3436	1	9,879	27,406.3333	1	45,722	50,311.6667
9	1,317	46,347	44.3786	1	6,397	14,714.0000	1	40,667	45,784.3667
10	1,317	47,570	37.7201	1	6,146	7,474.0000	1	39,588	
11	1,325	76,289	42.9922	1	10,774	7,772.3333	1	42,923	41,059.2667
12	1,337	143,812	67.2709	1	28,319	15,079.6667	1	52,828	45,112.8667
13	1,338	203,278	105.8448	1	76,329	38,474.0000	1	67,165	54,305.2333
14	15,878	1,575,717		12	537,378		12	639,787	

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; *Rapid City APO*

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	RESIDENTIAL RATE 60 CUSTOMERS (E)	RESIDENTIAL RATE 60 DEKATHERM SALES (F)	AVG USE 3 MONTH ENDING (G)	FIRM GENERAL SERVICE - SMALL METERS RATE 700 CUSTOMERS (H)	FIRM GENERAL SERVICE - SMALL METERS RATE 700 DEKATHERM SALES (I)	AVG USE 3 MONTH ENDING (J)
1	DEC	2002	1,233	1,027	N/A	N/A		N/A	N/A	
2	JAN	2003	1,314	1,198	36,257	476,231	10.7442	3,547	84,004	18.7258
3	FEB	2003	1,061	1,213	36,362	472,767	12.5210	3,557	87,546	22.7053
4	MAR	2003	925	924	36,379	452,431	12.8574	3,559	85,886	24.1429
5	APR	2003	595	505	36,324	285,540	11.1011	3,547	44,997	20.4848
6	MAY	2003	313	320	36,227	195,400	8.5685	3,530	27,101	14.8537
7	JUN	2003	88	54	36,169	113,424	5.4669	3,522	14,875	8.2058
8	JUL	2003	16	-	36,101	77,839	3.5638	3,525	10,470	4.9585
9	AUG	2003	21	17	36,147	59,025	2.3086	3,514	8,780	3.2312
10	SEP	2003	190	65	36,481	72,442	1.9250	3,522	9,186	2.6925
11	OCT	2003	521	385	36,873	132,851	2.4138	3,554	15,622	3.1717
12	NOV	2003	934	1,087	37,036	284,963	4.4411	3,579	45,393	6.5885
13	DEC	2003	1,233	1,063	37,153	425,458	7.5928	3,592	71,306	12.3376
14			7,211	6,831	437,509	3,048,371		42,548	505,166	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, Climatography of the United States No. 81 (Revised)
Column (D): NOAA Climatological Data for South Dakota Volume 107 Number 12 to Volume 108 Number 12
Columns (E), (F), (H), (I), (K), (L), (N), (O), (Q), and (R): MDU Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

LINE NO.	MONTH	YEAR	(A) NUMBER OF CUSTOMERS	(B) THERM SALES	(C) BASE LOAD SALES (THERM'S)	(D) TEMP. SENSITIVE SALES (THERM'S)	(E) NORMAL HEATING DD	(F) ACTUAL HEATING DD	(G) NORMALIZATION FACTOR	(H) UNBILLED NORMALIZED TEMP. SENSITIVE SALES (THERM'S)	(I) UNBILLED NORMALIZED TOTAL SALES (THERM'S)	(J) UNBILLED WEATHER ADJUSTMENT
						RATE:	RESIDENTIAL					
1	DEC	2003	37,153	212,729	35,760	176,969	1,030.4	1,033.0	0.99743	176,515	212,275	(454)
3	BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH =						0.962512	/ RESIDENTIAL				

LINE NO.	MONTH	YEAR	NUMBER OF CUSTOMERS	THERM SALES	BASE LOAD SALES (THERM'S)	TEMP. SENSITIVE SALES (THERM'S)	NORMAL HEATING DD	ACTUAL HEATING DD	NORMALIZATION FACTOR	UNBILLED NORMALIZED TEMP. SENSITIVE SALES (THERM'S)	UNBILLED NORMALIZED TOTAL SALES (THERM'S)	UNBILLED WEATHER ADJUSTMENT
						RATE:	FIRM GENERAL SERVICE - SMALL METERS					
5	DEC	2003	3,592	35,653	4,836	30,817	1,030.4	1,033.0	0.99743	30,738	35,574	(79)
						RATE:	FIRM GENERAL SERVICE - LARGE METERS					
6	DEC	2003	1,338	101,639	25,235	76,404	1,030.4	1,033.0	0.99743	76,208	101,443	(196)
7	BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH =						1.3463	/ FIRM GENERAL SERVICE - SMALL METERS				
8	BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH =						18.8601	/ FIRM GENERAL SERVICE - LARGE METERS				

Column (A), (B), (E), and (F): Exhibit ___ (MCB-1) Schedule 3-3
Column (C): Column (A) * Base Load

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

WEATHER STA RAPID CITY APO

LINE NO.	MONTH	YEAR	(A) NUMBER OF CUSTOMERS	(B) DEKATHERM SALES	(C) BASE LOAD SALES (THERM'S)	(D) TEMP. SENSITIVE SALES (DEKATHERM'S)	(E) NORMAL HEATING DD	(F) ACTUAL HEATING DD	(G) NORMALIZATION FACTOR	(H) UNBILLED NORMALIZED TEMP. SENSITIVE SALES (DEKATHERM'S)	(I) UNBILLED NORMALIZED TOTAL SALES (DEKATHERM'S)	(J) UNBILLED WEATHER ADJUSTMENT
									RATE:	RESIDENTIAL		
1	DEC	2002	36,257	(238,116)	(34,898)	(203,218)	1,329.4	1,107.5	1.20037	(243,936)	(278,834)	(40,719)
3	BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH =						0.962512	/ RESIDENTIAL				

LINE NO.	MONTH	YEAR	NUMBER OF CUSTOMERS	DEKATHERM SALES	BASE LOAD SALES (THERM'S)	TEMP. SENSITIVE SALES (DEKATHERM'S)	NORMAL HEATING DD	ACTUAL HEATING DD	NORMALIZATION FACTOR	UNBILLED NORMALIZED TEMP. SENSITIVE SALES (DEKATHERM'S)	UNBILLED NORMALIZED TOTAL SALES (DEKATHERM'S)	UNBILLED WEATHER ADJUSTMENT
									RATE:	FIRM GENERAL SERVICE - SMALL METERS		
5	DEC	2002	3,547	(42,002)	(4,775)	(37,227)	1,329.4	1,107.5	1.20037	(44,686)	(49,461)	(7,459)
									RATE:	FIRM GENERAL SERVICE - LARGE METERS		
6	DEC	2002	1,324	(113,207)	(24,971)	(88,236)	1,329.4	1,107.5	1.20037	(105,916)	(130,886)	(17,680)

7 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 1.3463 / FIRM GENERAL SERVICE - SMALL METERS
8 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 18.8601 / FIRM GENERAL SERVICE - LARGE METERS

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

REVENUE CLASS : RATE 702 - FIRM GENERAL SERVICE

LINE NO.	MONTH	YEAR	NUMBER OF CUSTOMERS	Dk SALES	BASE LOAD SALES (Dks)	TEMP. SENSITIVE SALES (Dks)	NORMAL HEATING DD	ACTUAL HEATING DD	NORMALIZATION FACTOR	NORMALIZED TEMP. SENSITIVE SALES (DksS)	NORMALIZED TOTAL SALES (Dks)	WEATHER ADJUSTMENT (Dks)
57	JAN	2003	1	51,632	41,059	10,573	1,233.0	1,027.0	1.20058	12,693	53,753	2,121
58	FEB	2003	1	56,802	41,059	15,742	1,273.0	1,209.0	1.05294	16,576	57,635	833
59	MAR	2003	1	68,296	41,059	27,236	1,061.0	1,212.0	0.87541	23,843	64,902	(3,393)
60	APR	2003	1	68,952	41,059	27,892	925.0	924.0	1.00108	27,923	68,982	30
61	MAY	2003	1	54,249	41,059	13,190	595.0	505.0	1.17822	15,541	56,600	2,351
62	JUN	2003	1	50,964	41,059	9,905	313.0	320.0	0.97813	9,688	50,747	(217)
63	JUL	2003	1	45,722	45,722	-	88.0	134.0	0.00000	-	45,722	-
64	AUG	2003	1	40,667	40,667	-	16.0	-	0.00000	-	40,667	-
65	SEP	2003	1	39,588	39,588	-	21.0	17.0	0.00000	-	39,588	-
66	OCT	2003	1	42,923	41,059	1,864	190.0	220.0	0.86364	1,610	42,669	(254)
67	NOV	2003	1	52,828	41,059	11,769	521.0	385.0	1.35325	15,926	56,985	4,157
68	DEC	2003	1	67,165	41,059	26,105	934.0	1,087.0	0.85925	22,431	63,490	(3,674)
69			12	639,787	495,510	144,277				146,230	641,740	1,954
70				BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING OCT					41,059.2667	/ RATE 702 - FIRM GENERAL SERVICE		

Sources:
Columns (C) and (D): Response to Data Request 1-30
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit ____ (MCB-8); Column (C) and (D) Exhibit___(MCB-1) Schedule 3-3
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)
Lines14, 28, 42, 56 and 70: Exhibit ____ (MCB-1) Schedule 3-3

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

REVENUE CLASS : ELLSWORTH AFB

LINE NO.	MONTH	YEAR	NUMBER OF CUSTOMERS	Dk SALES	BASE LOAD SALES (Dks)	TEMP. SENSITIVE SALES (Dks)	NORMAL HEATING DD	ACTUAL HEATING DD	NORMALIZATION FACTOR	NORMALIZED TEMP. SENSITIVE SALES (DksS)	NORMALIZED TOTAL SALES (Dks)	WEATHER ADJUSTMENT (Dks)
43	JAN	2003	1	79,083	7,474	71,609	1,233.0	1,027.0	1.20058	85,973	93,447	14,364
44	FEB	2003	1	89,581	7,474	82,107	1,273.0	1,209.0	1.05294	86,453	93,927	4,346
45	MAR	2003	1	82,805	7,474	75,331	1,061.0	1,212.0	0.87541	65,946	73,420	(9,385)
46	APR	2003	1	75,725	7,474	68,251	925.0	924.0	1.00108	68,325	75,799	74
47	MAY	2003	1	44,474	7,474	37,000	595.0	505.0	1.17822	43,594	51,068	6,594
48	JUN	2003	1	27,866	7,474	20,392	313.0	320.0	0.97813	19,946	27,420	(446)
49	JUL	2003	1	9,879	9,879	-	88.0	134.0	0.00000	-	9,879	-
50	AUG	2003	1	6,397	6,397	-	16.0	-	0.00000	-	6,397	-
51	SEP	2003	1	6,146	6,146	-	21.0	17.0	0.00000	-	6,146	-
52	OCT	2003	1	10,774	7,474	3,300	190.0	220.0	0.86364	2,850	10,324	(450)
53	NOV	2003	1	28,319	7,474	20,845	521.0	385.0	1.35325	28,208	35,682	7,363
54	DEC	2003	1	76,329	7,474	68,855	934.0	1,087.0	0.85925	59,163	66,637	(9,692)
55			12	537,378	89,688	447,690				460,458	550,146	12,768

56 BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING SEP 7,474.0000 / ELLSWORTH AFB

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

REVENUE CLASS : FIRM GENERAL SERVICE - SMALL METERS

LINE NO.	MONTH	YEAR	NUMBER OF CUSTOMERS	Dk SALES	BASE LOAD SALES (Dks)	TEMP. SENSITIVE SALES (Dks)	NORMAL HEATING DD	ACTUAL HEATING DD	NORMALIZATION FACTOR	NORMALIZED TEMP. SENSITIVE SALES (DksS)	NORMALIZED TOTAL SALES (Dks)	WEATHER ADJUSTMENT (Dks)
15	JAN	2003	3,547	84,004	9,550	74,454	1,329.4	1,107.5	1.20037	89,372	98,922	14,918
16	FEB	2003	3,557	87,546	9,577	77,969	1,268.5	1,276.4	0.99381	77,486	87,063	(483)
17	MAR	2003	3,559	85,886	9,583	76,303	970.5	1,134.0	0.85582	65,302	74,885	(11,001)
18	APR	2003	3,547	44,997	9,550	35,447	757.5	661.2	1.14573	40,612	50,163	5,166
19	MAY	2003	3,530	27,101	9,505	17,596	496.9	471.6	1.05354	18,538	28,043	942
20	JUN	2003	3,522	14,875	9,483	5,392	209.8	220.3	0.95234	5,135	14,618	(257)
21	JUL	2003	3,525	10,470	10,470	-	50.6	60.1	0.00000	-	10,470	-
22	AUG	2003	3,514	8,780	8,780	-	7.7	0.3	0.00000	-	8,780	-
23	SEP	2003	3,522	9,186	9,186	-	76.3	61.0	0.00000	-	9,186	-
24	OCT	2003	3,554	15,622	9,569	6,053	294.4	275.0	1.07036	6,479	16,048	426
25	NOV	2003	3,579	45,393	9,637	35,756	691.1	722.8	0.95614	34,188	43,825	(1,568)
26	DEC	2003	3,592	71,306	9,672	61,634	1,030.4	1,033.0	0.99743	61,476	71,148	(158)
27			42,548	505,166	114,563	390,603				398,588	513,151	7,985
28				*BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING SEP					2.6925	/ FIRM GENERAL SERVICE - SMALL METERS		

REVENUE CLASS : FIRM GENERAL SERVICE - LARGE METERS

LINE NO.	MONTH	YEAR	NUMBER OF CUSTOMERS	Dk SALES	BASE LOAD SALES (Dks)	TEMP. SENSITIVE SALES (Dks)	NORMAL HEATING DD	ACTUAL HEATING DD	NORMALIZATION FACTOR	NORMALIZED TEMP. SENSITIVE SALES (DksS)	NORMALIZED TOTAL SALES (Dks)	WEATHER ADJUSTMENT (Dks)
29	JAN	2003	1,324	226,413	49,941	176,472	1,329.4	1,107.5	1.20037	211,831	261,773	35,360
30	FEB	2003	1,322	228,615	49,866	178,749	1,268.5	1,276.4	0.99381	177,643	227,509	(1,106)
31	MAR	2003	1,321	229,413	49,828	179,585	970.5	1,134.0	0.85582	153,692	203,520	(25,893)
32	APR	2003	1,319	143,056	49,753	93,303	757.5	661.2	1.14573	106,900	156,653	13,597
33	MAY	2003	1,321	101,798	49,828	51,970	496.9	471.6	1.05354	54,752	104,581	2,783
34	JUN	2003	1,319	73,973	49,753	24,220	209.8	220.3	0.95234	23,066	72,819	(1,154)
35	JUL	2003	1,318	55,153	55,153	-	50.6	60.1	0.00000	-	55,153	-
36	AUG	2003	1,317	46,347	46,347	-	7.7	0.3	0.00000	-	46,347	-
37	SEP	2003	1,317	47,570	47,570	-	76.3	61.0	0.00000	-	47,570	-
38	OCT	2003	1,325	76,289	49,979	26,310	294.4	275.0	1.07036	28,161	78,140	1,851
39	NOV	2003	1,337	143,812	50,432	93,380	691.1	722.8	0.95614	89,285	139,717	(4,095)
40	DEC	2003	1,338	203,278	50,470	152,808	1,030.4	1,033.0	0.99743	152,416	202,886	(392)
41			15,878	1,575,717	598,920	976,797				997,746	1,596,667	20,950
42				*BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING SEP					37.7201	/ FIRM GENERAL SERVICE - LARGE METERS		

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending December 31, 2003

WEATHER STATION: Rapid City
REVENUE CLASS : RESIDENTIAL

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) Dk SALES	(E) BASE LOAD SALES (Dks)	(F) TEMP. SENSITIVE SALES (Dks)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DksS)	(K) NORMALIZED TOTAL SALES (Dks)	(L) WEATHER ADJUSTMENT (Dks)
1	JAN	2003	36,257	476,231	69,796	406,435	1,329.4	1,107.5	1.20037	487,873	557,669	81,438
2	FEB	2003	36,362	472,767	69,998	402,769	1,268.5	1,276.4	0.99381	400,276	470,274	(2,493)
3	MAR	2003	36,379	452,431	70,030	382,401	970.5	1,134.0	0.85582	327,266	397,297	(55,134)
4	APR	2003	36,324	285,540	69,925	215,615	757.5	661.2	1.14573	247,037	316,962	31,422
5	MAY	2003	36,227	195,400	69,738	125,662	496.9	471.6	1.05354	132,390	202,128	6,728
6	JUN	2003	36,169	113,424	69,626	43,798	209.8	220.3	0.95234	41,710	111,336	(2,088)
7	JUL	2003	36,101	77,839	77,839	-	50.6	60.1	0.00000	-	77,839	-
8	AUG	2003	36,147	59,025	59,025	-	7.7	0.3	0.00000	-	59,025	-
9	SEP	2003	36,481	72,442	72,442	-	76.3	61.0	0.00000	-	72,442	-
10	OCT	2003	36,873	132,851	70,981	61,870	294.4	275.0	1.07036	66,223	137,204	4,353
11	NOV	2003	37,036	284,963	71,295	213,668	691.1	722.8	0.95614	204,297	275,592	(9,371)
12	DEC	2003	37,153	425,458	71,520	353,938	1,030.4	1,033.0	0.99743	353,030	424,550	(908)
13			437,509	3,048,371	842,216	2,206,155				2,260,102	3,102,318	53,947
14	BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING SEP								1.9250	/ RESIDENTIAL - SMALL METERS		

Montana-Dakota Utilities
South Dakota - Gas
Rate 71 Small Interruptible
Weather Normalization
Test Year Ending December 31, 2003

RATE 710 SMALL INTERRUPTIBLE COMBINED

LINE NO.	(A) CUSTOMER ID NO.	(B) Dk SALES	(C) BASE LOAD SALES (Dk)	(D) TEMP. SENSITIVE SALES (Dk)	(E) NORMALIZED TEMP. SENSITIVE SALES (Dk)	(F) NORMALIZED TOTAL SALES (Dk)	(G) WEATHER ADJUSTMENT (Dk)
1	167	5,455	3,048	2,407	2,487	5,535	80
2	522	598	133	465	474	607	8
3	527	2,186	68	2,118	2,229	2,297	111
4	532	4,863	2,767	2,096	2,109	4,876	13
5	533	3,183	227	2,956	3,047	3,274	91
6	539	6,133	289	5,844	5,995	6,284	151
7	554	2,301	13	2,145	2,201	2,357	57
8	555	6,904	5,829	1,076	1,095	6,923	19
9	SUBTOTAL	31,622	12,373	19,105	19,637	32,153	531
None Weather Sensitive Customers							
10	556	2,087				2,087	
11	540	1,306				1,306	
12	574	14				14	
13	222	48				48	
14	558	0				0	
15	SUBTOTAL	3,454				3,454	
16	TOTAL	35,076				35,607	

Sources:
Lines 1 - 8: Exhibit____(MCB-2) Schedule 3-1 to 10-1
Lines 10 - 15: Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Rate 71 Small Interruptible
Weather Normalization Unbilled Sales
Test Year Ending December 31, 2003

WEATHER STATION: RAPID CITY APO

RATE: 71 SMALL INTERRUPTIBLE

LINE NO.	MONTH	YEAR	(A) NUMBER OF CUSTOMERS	(B) DKT SALES	(C) BASE LOAD SALES (DKS)	(D) TEMP. SENSITIVE SALES (DK'S)	(E) NORMAL HEATING DD	(F) ACTUAL HEATING DD	(G) NORMALIZATION FACTOR	(H) UNBILLED NORMALIZED TEMP. SENSITIVE SALES (DK'S)	(I) UNBILLED NORMALIZED TOTAL SALES (DK'S)	(J) UNBILLED WEATHER ADJUSTMENT
1	DEC	2002	8	(7,560)	(2,357)	(5,203)	1,329.4	1,107.5	1.20037	(6,245)	(8,603)	(1,042)
2	DEC	2003	6	5,839	1,768	4,071	1,030.4	1,033.0	0.99743	4,060	5,828	(10)

3 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 294.668750 / RATE 71 - SMALL INTERRUPTIBLE

Sources:

Column (A): Response ro Data request No. 1-4
Column (B): One Half June Sales to Weather Sensitive Customers; Exhibit____(MCB-2) Schedule 3-1 to 10-1
Column (C): Column (A) * Baseload
Column (E) and (F): Exhibit____(MCB-2) Schedule 3-1, Actual and Normal HDD

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 167
Test Year Ending December 31, 2003

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 167

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) DkT SALES	(E) BASE LOAD SALES (DkT)	(F) TEMP. SENSITIVE SALES (DkT)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DkT)	(K) NORMALIZED TOTAL SALES (DkT)	(L) WEATHER ADJUSTMENT (DkT)
1	JAN	2003	1	821.3	338.6	482.7	1,329	1,107	1.20037	579.4	918.0	96.7
2	FEB	2003	1	881.7	338.6	543.1	1,268	1,276	0.99381	539.7	878.3	(3.4)
3	MAR	2003	1	884.2	338.6	545.6	971	1,134	0.85582	466.9	805.5	(78.7)
4	APR	2003	1	773.0	338.6	434.4	758	661	1.14573	497.7	836.3	63.3
5	MAY	2003	1	548.4	338.6	209.8	497	472	1.05354	221.0	559.6	11.2
6	JUN	2003	1	530.0	338.6	191.4	210	220	0.95234	182.3	520.9	(9.1)
7	JUL	2003	1	456.9	456.9	-	51	60	0.00000	-	456.9	-
8	AUG	2003	1	270.2	270.2	-	8	0	0.00000	-	270.2	-
9	SEP	2003	1	288.8	288.8	-	76	61	0.00000	-	288.8	-
10	OCT	2003	-	-	-	-	294	275	1.07036	-	-	-
11	NOV	2003	-	-	-	-	691	723	0.95614	-	-	-
12	DEC	2003	-	-	-	-	1,030	1,033	0.99743	-	-	-
13			9	5,454.5	3,047.5	2,407.0				2,487.1	5,534.6	80.1

Sources:
Column (C) and (D): Exhibit____(MCB-2) Schedule 3-2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit____(MCB-8)
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Customer ID No. 167
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH	YEAR	DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	CUSTOMER ID 167 CUSTOMERS	CUSTOMER ID 167 DK THERM SALES	AVG USE 3 MONTH ENDING
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	1	821.3	821.3000
3	FEB	2003	1,061	1,213	1	881.7	851.5000
4	MAR	2003	925	924	1	884.2	862.4000
5	APR	2003	595	505	1	773.0	846.3000
6	MAY	2003	313	320	1	548.4	735.2000
7	JUN	2003	88	54	1	530.0	617.1333
8	JUL	2003	16	-	1	456.9	511.7667
9	AUG	2003	21	17	1	270.2	419.0333
10	SEP	2003	190	65	1	288.8	338.6333
11	OCT	2003	521	385	-	-	279.5000
12	NOV	2003	934	1,087	-	-	288.8000
13	DEC	2003	1,233	1,063	-	-	#DIV/0!
14			7,211	6,831	9	5,454.5	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, Climatography of the United States No. 81
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): MDU Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 522
Test Year Ending December 31, 2003

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 522

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) DkT SALES	(E) BASE LOAD SALES (DkT)	(F) TEMP. SENSITIVE SALES (DkT)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DkT)	(K) NORMALIZED TOTAL SALES (DkT)	(L) WEATHER ADJUSTMENT (DkT)
1	JAN	2003	1	71.5	11.1	60.4	1,329	1,107	1.20037	72.5	83.6	12.1
2	FEB	2003	1	78.2	11.1	67.1	1,268	1,276	0.99381	66.7	77.8	(0.4)
3	MAR	2003	1	89.6	11.1	78.5	971	1,134	0.85582	67.2	78.3	(11.3)
4	APR	2003	1	65.9	11.1	54.8	758	661	1.14573	62.8	73.9	8.0
5	MAY	2003	1	53.0	11.1	41.9	497	472	1.05354	44.1	55.2	2.2
6	JUN	2003	1	34.0	11.1	22.9	210	220	0.95234	21.8	32.9	(1.1)
7	JUL	2003	1	13.8	13.8	-	51	60	0.00000	-	13.8	-
8	AUG	2003	1	7.5	7.5	-	8	0	0.00000	-	7.5	-
9	SEP	2003	1	11.9	11.9	-	76	61	0.00000	-	11.9	-
10	OCT	2003	1	33.6	11.1	22.5	294	275	1.07036	24.1	35.2	1.6
11	NOV	2003	1	69.0	11.1	57.9	691	723	0.95614	55.4	66.5	(2.5)
12	DEC	2003	1	70.4	11.1	59.3	1,030	1,033	0.99743	59.1	70.2	(0.2)
13			12	598.4	133.1	465.3				473.7	606.8	8.4

Sources:
Column (C) and (D): Exhibit____(MCB-2) Schedule 4-2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit____(MCB-8)
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Customer ID No. 522
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 522 CUSTOMERS (E)	CUSTOMER ID 522 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	1	71.5	70.3000
3	FEB	2003	1,061	1,213	1	78.2	73.3667
4	MAR	2003	925	924	1	89.6	79.7667
5	APR	2003	595	505	1	65.9	77.9000
6	MAY	2003	313	320	1	53.0	69.5000
7	JUN	2003	88	54	1	34.0	50.9667
8	JUL	2003	16	-	1	13.8	33.6000
9	AUG	2003	21	17	1	7.5	18.4333
10	SEP	2003	190	65	1	11.9	11.0667
11	OCT	2003	521	385	1	33.6	17.6667
12	NOV	2003	934	1,087	1	69.0	38.1667
13	DEC	2003	1,233	1,063	1	70.4	57.6667
14			7,211	6,831	12	598.4	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, Climatography of the United States No. 81
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): MDU Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 527
Test Year Ending December 31, 2003

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 527

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) DkT SALES	(E) BASE LOAD SALES (DkT)	(F) TEMP. SENSITIVE SALES (DkT)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DkT)	(K) NORMALIZED TOTAL SALES (DkT)	(L) WEATHER ADJUSTMENT (DkT)
1	JAN	2003	1	547.2	6.8	540.4	1,329	1,107	1.20037	648.7	655.5	108.3
2	FEB	2003	1	553.3	6.8	546.5	1,268	1,276	0.99381	543.1	549.9	(3.4)
3	MAR	2003	1	357.7	6.8	350.9	971	1,134	0.85582	300.3	307.1	(50.6)
4	APR	2003	1	309.6	6.8	302.8	758	661	1.14573	346.9	353.7	44.1
5	MAY	2003	1	248.0	6.8	241.2	497	472	1.05354	254.1	260.9	12.9
6	JUN	2003	1	86.9	6.8	80.1	210	220	0.95234	76.3	83.1	(3.8)
7	JUL	2003	1	7.7	7.7	-	51	60	0.00000	-	7.7	-
8	AUG	2003	1	6.4	6.4	-	8	0	0.00000	-	6.4	-
9	SEP	2003	1	6.2	6.2	-	76	61	0.00000	-	6.2	-
10	OCT	2003	1	62.5	6.8	55.7	294	275	1.07036	59.6	66.4	3.9
11	NOV	2003	-	-	-	-	691	723	0.95614	-	-	-
12	DEC	2003	-	-	-	-	1,030	1,033	0.99743	-	-	-
13			10	2,185.5	67.9	2,117.6				2,229.0	2,296.9	111.4

Sources:
Column (C) and (D): Exhibit____(MCB-2) Schedule 5-2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit____(MCB-8)
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Customer ID No. 527
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH	YEAR	DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	CUSTOMER ID 527 CUSTOMERS	CUSTOMER ID 527 DK THERM SALES	AVG USE 3 MONTH ENDING
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	1	547.2	547.2000
3	FEB	2003	1,061	1,213	1	553.3	550.2500
4	MAR	2003	925	924	1	357.7	486.0667
5	APR	2003	595	505	1	309.6	406.8667
6	MAY	2003	313	320	1	248.0	305.1000
7	JUN	2003	88	54	1	86.9	214.8333
8	JUL	2003	16	-	1	7.7	114.2000
9	AUG	2003	21	17	1	6.4	33.6667
10	SEP	2003	190	65	1	6.2	6.7667
11	OCT	2003	521	385	1	62.5	25.0333
12	NOV	2003	934	1,087	-	-	34.3500
13	DEC	2003	1,233	1,063	-	-	62.5000
14			7,211	6,831	10	2,185.5	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, *Climatography of the United States No. 81*
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): MDU Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 532
Test Year Ending December 31, 2003

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 532

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) DkT SALES	(E) BASE LOAD SALES (DkT)	(F) TEMP. SENSITIVE SALES (DkT)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DkT)	(K) NORMALIZED TOTAL SALES (DkT)	(L) WEATHER ADJUSTMENT (DkT)
1	JAN	2003	1	563.8	230.6	333.2	1,329	1,107	1.20037	400.0	630.6	66.8
2	FEB	2003	1	348.5	230.6	117.9	1,268	1,276	0.99381	117.2	347.8	(0.7)
3	MAR	2003	1	831.7	230.6	601.1	971	1,134	0.85582	514.4	745.0	(86.7)
4	APR	2003	1	468.6	230.6	238.0	758	661	1.14573	272.7	503.3	34.7
5	MAY	2003	1	346.9	230.6	116.3	497	472	1.05354	122.5	353.1	6.2
6	JUN	2003	1	306.0	230.6	75.4	210	220	0.95234	71.8	302.4	(3.6)
7	JUL	2003	1	283.4	283.4	-	51	60	0.00000	-	283.4	-
8	AUG	2003	1	195.1	195.1	-	8	0	0.00000	-	195.1	-
9	SEP	2003	1	213.4	213.4	-	76	61	0.00000	-	213.4	-
10	OCT	2003	1	314.2	230.6	83.6	294	275	1.07036	89.5	320.1	5.9
11	NOV	2003	1	428.5	230.6	197.9	691	723	0.95614	189.2	419.8	(8.7)
12	DEC	2003	1	563.1	230.6	332.5	1,030	1,033	0.99743	331.6	562.2	(0.9)
13			12	4,863.2	2,767.3	2,095.9				2,108.9	4,876.2	13.0

Sources:
Column (C) and (D): *Exhibit____(MCB-2) Schedule 6-2*
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit____(MCB-8)
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Customer ID No. 532
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH	YEAR	DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	CUSTOMER ID 532 CUSTOMERS	CUSTOMER ID 532 DK THERM SALES	AVG USE 3 MONTH ENDING
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	1	563.8	518.4667
3	FEB	2003	1,061	1,213	1	348.5	491.8000
4	MAR	2003	925	924	1	831.7	581.3333
5	APR	2003	595	505	1	468.6	549.6000
6	MAY	2003	313	320	1	346.9	549.0667
7	JUN	2003	88	54	1	306.0	373.8333
8	JUL	2003	16	-	1	283.4	312.1000
9	AUG	2003	21	17	1	195.1	261.5000
10	SEP	2003	190	65	1	213.4	230.6333
11	OCT	2003	521	385	1	314.2	240.9000
12	NOV	2003	934	1,087	1	428.5	318.7000
13	DEC	2003	1,233	1,063	1	563.1	435.2667
14			7,211	6,831	12	4,863.2	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, Climatography of the United States No. 81
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): MDU Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 533
Test Year Ending December 31, 2003

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 533

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) DkT SALES	(E) BASE LOAD SALES (DkT)	(F) TEMP. SENSITIVE SALES (DkT)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DkT)	(K) NORMALIZED TOTAL SALES (DkT)	(L) WEATHER ADJUSTMENT (DkT)
1	JAN	2003	1	610.6	18.9	591.7	1,329	1,107	1.20037	710.3	729.2	118.6
2	FEB	2003	1	505.1	18.9	486.2	1,268	1,276	0.99381	483.2	502.1	(3.0)
3	MAR	2003	1	469.4	18.9	450.5	971	1,134	0.85582	385.5	404.4	(65.0)
4	APR	2003	1	309.6	18.9	290.7	758	661	1.14573	333.1	352.0	42.4
5	MAY	2003	1	144.2	18.9	125.3	497	472	1.05354	132.0	150.9	6.7
6	JUN	2003	1	92.1	18.9	73.2	210	220	0.95234	69.7	88.6	(3.5)
7	JUL	2003	1	12.4	12.4	-	51	60	0.00000	-	12.4	-
8	AUG	2003	1	10.1	10.1	-	8	0	0.00000	-	10.1	-
9	SEP	2003	1	34.3	34.3	-	76	61	0.00000	-	34.3	-
10	OCT	2003	1	184.6	18.9	165.7	294	275	1.07036	177.4	196.3	11.7
11	NOV	2003	1	371.6	18.9	352.7	691	723	0.95614	337.2	356.1	(15.5)
12	DEC	2003	1	438.8	18.9	419.9	1,030	1,033	0.99743	418.8	437.7	(1.1)
13			12	3,182.8	226.9	2,955.9				3,047.2	3,274.1	91.3

Sources:
Column (C) and (D): Exhibit____(MCB-2) Schedule 7-2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit____(MCB-8)
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Customer ID No. 533
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH	YEAR	DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	CUSTOMER ID 533 CUSTOMERS	CUSTOMER ID 533 DK THERM SALES	AVG USE 3 MONTH ENDING
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	1	610.6	473.6667
3	FEB	2003	1,061	1,213	1	505.1	518.1667
4	MAR	2003	925	924	1	469.4	528.3667
5	APR	2003	595	505	1	309.6	428.0333
6	MAY	2003	313	320	1	144.2	307.7333
7	JUN	2003	88	54	1	92.1	181.9667
8	JUL	2003	16	-	1	12.4	82.9000
9	AUG	2003	21	17	1	10.1	38.2000
10	SEP	2003	190	65	1	34.3	18.9333
11	OCT	2003	521	385	1	184.6	76.3333
12	NOV	2003	934	1,087	1	371.6	196.8333
13	DEC	2003	1,233	1,063	1	438.8	331.6667
14			7,211	6,831	12	3,182.8	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, Climatography of the United States No. 81
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): MDU Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 539
Test Year Ending December 31, 2003

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 539

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
LINE NO.	MONTH	YEAR	NUMBER OF CUSTOMERS	DkT SALES	BASE LOAD SALES (DkT)	TEMP. SENSITIVE SALES (DkT)	NORMAL HEATING DD	ACTUAL HEATING DD	NORMALIZATION FACTOR	NORMALIZED TEMP. SENSITIVE SALES (DkT)	NORMALIZED TOTAL SALES (DkT)	WEATHER ADJUSTMENT (DkT)
1	JAN	2003	1	1,173.7	24.1	1,149.6	1,329	1,107	1.20037	1,379.9	1,404.0	230.3
2	FEB	2003	1	1,157.9	24.1	1,133.8	1,268	1,276	0.99381	1,126.8	1,150.9	(7.0)
3	MAR	2003	1	1,042.8	24.1	1,018.7	971	1,134	0.85582	871.8	895.9	(146.9)
4	APR	2003	1	504.6	24.1	480.5	758	661	1.14573	550.5	574.6	70.0
5	MAY	2003	1	346.5	24.1	322.4	497	472	1.05354	339.7	363.8	17.3
6	JUN	2003	1	194.6	24.1	170.5	210	220	0.95234	162.4	186.5	(8.1)
7	JUL	2003	1	30.1	30.1	-	51	60	0.00000	-	30.1	-
8	AUG	2003	1	21.8	21.8	-	8	0	0.00000	-	21.8	-
9	SEP	2003	1	20.4	20.4	-	76	61	0.00000	-	20.4	-
10	OCT	2003	1	319.5	24.1	295.4	294	275	1.07036	316.2	340.3	20.8
11	NOV	2003	1	556.9	24.1	532.8	691	723	0.95614	509.4	533.5	(23.4)
12	DEC	2003	1	764.0	24.1	739.9	1,030	1,033	0.99743	738.0	762.1	(1.9)
13			12	6,132.8	289.2	5,843.6				5,994.7	6,283.9	151.1

Sources:
Column (C) and (D): Exhibit____(MCB-2) Schedule 8-2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit____(MCB-8)
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Customer ID No. 539
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH	YEAR	DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	CUSTOMER ID 539 CUSTOMERS	CUSTOMER ID 539 DK THERM SALES	AVG USE 3 MONTH ENDING
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	1	1,173.7	831.5333
3	FEB	2003	1,061	1,213	1	1,157.9	1,031.8667
4	MAR	2003	925	924	1	1,042.8	1,124.8000
5	APR	2003	595	505	1	504.6	901.7667
6	MAY	2003	313	320	1	346.5	631.3000
7	JUN	2003	88	54	1	194.6	348.5667
8	JUL	2003	16	-	1	30.1	190.4000
9	AUG	2003	21	17	1	21.8	82.1667
10	SEP	2003	190	65	1	20.4	24.1000
11	OCT	2003	521	385	1	319.5	120.5667
12	NOV	2003	934	1,087	1	556.9	298.9333
13	DEC	2003	1,233	1,063	1	764.0	546.8000
14			7,211	6,831	12	6,132.8	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, Climatography of the United States No. 81
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): MDU Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 554
Test Year Ending December 31, 2003

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 554

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) DkT SALES	(E) BASE LOAD SALES (DkT)	(F) TEMP. SENSITIVE SALES (DkT)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DkT)	(K) NORMALIZED TOTAL SALES (DkT)	(L) WEATHER ADJUSTMENT (DkT)
1	JAN	2003	1	470.0	13.0	457.0	1,329	1,107	1.20037	549	562	92
2	FEB	2003	1	520.0	13.0	507.0	1,268	1,276	0.99381	504	517	(3)
3	MAR	2003	1	455.8	13.0	442.8	971	1,134	0.85582	379	392	(64)
4	APR	2003	1	226.6	13.0	213.6	758	661	1.14573	245	258	31
5	MAY	2003	1	147.0	13.0	134.0	497	472	1.05354	141	154	7
6	JUN	2003	1	47.5	13.0	34.5	210	220	0.95234	33	46	(2)
7	JUL	2003	1	13.7	13.7	-	51	60	0.00000	-	14	-
8	AUG	2003	1	22.3	22.3	-	8	0	0.00000	-	22	-
9	SEP	2003	1	3.0	3.0	-	76	61	0.00000	-	3	-
10	OCT	2003	1	113.7	13.0	100.7	294	275	1.07036	108	121	7
11	NOV	2003	1	281.0	13.0	268.0	691	723	0.95614	256	269	(12)
12	DEC	2003	-	-	13.0	(13.0)	1,030	1,033	0.99743	(13)	0	0
13			11	2,300.6	156.0	2,144.6				2,201	2,357	57

Sources:
Column (C) and (D): Exhibit____(MCB-2) Schedule 9-2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit____(MCB-8)
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Customer ID No. 554
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH	YEAR	DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	CUSTOMER ID 554 CUSTOMERS	CUSTOMER ID 554 DK THERM SALES	AVG USE 3 MONTH ENDING
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	1	470.0	375.5000
3	FEB	2003	1,061	1,213	1	520.0	495.0000
4	MAR	2003	925	924	1	455.8	481.9333
5	APR	2003	595	505	1	226.6	400.8000
6	MAY	2003	313	320	1	147.0	276.4667
7	JUN	2003	88	54	1	47.5	140.3667
8	JUL	2003	16	-	1	13.7	69.4000
9	AUG	2003	21	17	1	22.3	27.8333
10	SEP	2003	190	65	1	3.0	13.0000
11	OCT	2003	521	385	1	113.7	46.3333
12	NOV	2003	934	1,087	1	281.0	132.5667
13	DEC	2003	1,233	1,063	-	-	197.3500
14			7,211	6,831	11	2,300.6	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, Climatography of the United States No. 81
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): MDU Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 555
Test Year Ending December 31, 2003

WEATHER STATION: *Rapid City*
REVENUE CLASS : CUSTOMER ID 555

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) DkT SALES	(E) BASE LOAD SALES (DkT)	(F) TEMP. SENSITIVE SALES (DkT)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DkT)	(K) NORMALIZED TOTAL SALES (DkT)	(L) WEATHER ADJUSTMENT (DkT)
1	JAN	2003	1	677.0	485.7	191.3	1,329	1,107	1.20037	229.6	715.3	38.3
2	FEB	2003	1	607.5	485.7	121.8	1,268	1,276	0.99381	121.0	606.7	(0.8)
3	MAR	2003	1	691.4	485.7	205.7	971	1,134	0.85582	176.0	661.7	(29.7)
4	APR	2003	1	536.4	485.7	50.7	758	661	1.14573	58.1	543.8	7.4
5	MAY	2003	1	552.5	485.7	66.8	497	472	1.05354	70.4	556.1	3.6
6	JUN	2003	1	532.2	485.7	46.5	210	220	0.95234	44.3	530.0	(2.2)
7	JUL	2003	1	516.3	516.3	-	51	60	0.00000	-	516.3	-
8	AUG	2003	1	442.0	442.0	-	8	0	0.00000	-	442.0	-
9	SEP	2003	1	498.9	498.9	-	76	61	0.00000	-	498.9	-
10	OCT	2003	1	599.4	485.7	113.7	294	275	1.07036	121.7	607.4	8.0
11	NOV	2003	1	597.2	485.7	111.5	691	723	0.95614	106.6	592.3	(4.9)
12	DEC	2003	1	653.2	485.7	167.5	1,030	1,033	0.99743	167.1	652.8	(0.4)
13			12	6,904.0	5,828.5	1,075.5				1,094.8	6,923.3	19.3

Sources:
Column (C) and (D): Exhibit___(MCB-2) Schedule 10-2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit___(MCB-8)
Column (I): Column (G) / Column (H)
*Column (J): Column (F) * Column (I)*
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Customer ID No. 555
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 555 CUSTOMERS (E)	CUSTOMER ID 555 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	1	677.0	642.4667
3	FEB	2003	1,061	1,213	1	607.5	645.9000
4	MAR	2003	925	924	1	691.4	658.6333
5	APR	2003	595	505	1	536.4	611.7667
6	MAY	2003	313	320	1	552.5	593.4333
7	JUN	2003	88	54	1	532.2	540.3667
8	JUL	2003	16	-	1	516.3	533.6667
9	AUG	2003	21	17	1	442.0	496.8333
10	SEP	2003	190	65	1	498.9	485.7333
11	OCT	2003	521	385	1	599.4	513.4333
12	NOV	2003	934	1,087	1	597.2	565.1667
13	DEC	2003	1,233	1,063	1	653.2	616.6000
14			7,211	6,831	12	6,904.0	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, Climatography of the United States No. 81
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): MDU Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Rate 81 Small Interruptible Transportation
Test Year Ending December 31, 2003

WEATHER STATION: Rapid City
REVENUE CLASS : RATE 81 - SMALL INTERRUPTIBLE TRANSPORTATION

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) Dk SALES	(E) BASE LOAD SALES (DkT)	(F) TEMP. SENSITIVE SALES (DkT)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DkT)	(K) NORMALIZED TOTAL SALES (DkT)	(L) WEATHER ADJUSTMENT (DkT)
1	JAN	2003	16	19,293	3,725	15,568	1,233.0	1,027.0	1.20058	18,691	22,416	3,123
2	FEB	2003	16	22,327	3,725	18,602	1,314.0	1,198.0	1.09683	20,403	24,128	1,801
3	MAR	2003	16	22,672	3,725	18,947	1,061.0	1,213.0	0.87469	16,573	20,297	(2,374)
4	APR	2003	16	18,139	3,725	14,414	925.0	924.0	1.00108	14,429	18,154	16
5	MAY	2003	16	9,762	3,725	6,038	595.0	505.0	1.17822	7,114	10,838	1,076
6	JUN	2003	16	6,780	3,725	3,055	313.0	320.0	0.97813	2,988	6,713	(67)
7	JUL	2003	16	3,171	3,171	-	88.0	54.0	0.00000	-	3,171	-
8	AUG	2003	16	3,823	3,823	-	16.0	-	0.00000	-	3,823	-
9	SEP	2003	16	4,181	4,181	-	21.0	17.0	0.00000	-	4,181	-
10	OCT	2003	16	5,387	3,725	1,662	190.0	65.0	2.92308	4,859	8,584	3,197
11	NOV	2003	16	8,629	3,725	4,904	521.0	385.0	1.35325	6,636	10,361	1,732
12	DEC	2003	16	19,906	3,725	16,181	934.0	1,087.0	0.85925	13,904	17,628	(2,278)
13			192	144,069	44,698	99,370				105,597	150,295	6,226

Non-Weather Sensitive Customers

	CUSTOMER ID NO.		
14	257	17,849	17,849
15	114	16,329	16,329
16	153	14,081	14,081
17	526	11,051	11,051
18	127	14,458	14,458
19	239	19,904	19,904
20	3	14,594	14,594
21	129	33,933	33,933
22	105	7,548	7,548
23	115	21,495	21,495
24	261	16,505	16,505
25	264	17,504	17,504
26	229	5,282	5,282
27	SUBTOTAL	210,533	210,533
28	TOTAL	354,602	**360,828**

Sources:
Column (C) and (D): Exhibit____(MCB-3) Schedule 1-2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit____(MCB-3) Schedule 1-2
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)
Line 14 to 16: Response to Staff Data Request No. 1-4

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Rate 81 Small Interruptible Transportation
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH	YEAR	DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	Rate 81 Small Interruptible Transport CUSTOMERS	Rate 81 Small Interruptible Transport DK THERM SALES	AVG USE 3 MONTH ENDING
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	16	19,293	996.4125
3	FEB	2003	1,061	1,213	16	22,327	1,281.7813
4	MAR	2003	925	924	16	22,672	1,339.3979
5	APR	2003	595	505	16	18,139	1,315.3479
6	MAY	2003	313	320	16	9,762	1,053.5938
7	JUN	2003	88	54	16	6,780	722.5188
8	JUL	2003	16	-	16	3,171	410.7042
9	AUG	2003	21	17	16	3,823	286.9604
10	SEP	2003	190	65	16	4,181	232.8042
11	OCT	2003	521	385	16	5,387	278.9688
12	NOV	2003	934	1,087	16	8,629	379.0979
13	DEC	2003	1,233	1,063	16	19,906	706.7125
14			7,211	6,831	192	144,069	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, Climatography of the United States No. 81 (Revised)
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): Exhibit____(MCB-3) Schedule 2

Montana-Dakota Utilities
South Dakota - Gas
Usage Analysis
Rate 81 Small Interruptible Transportation
Test Year Ending December 31, 2003

Rate 810 Customer Usage by Month - DekaTherms

Line		Customer ID Nos.									
No.	Month	194	136	145	531	39	523	197	524	215	529
1	Jan-03	644.8	547.8	845.0	504.3	1,200.2	1,971.9	1,466.5	197.6	480.6	1,444.8
2	Feb-03	670.0	597.0	908.6	647.5	1,343.8	2,318.8	1,584.8	229.1	628.7	1,674.1
3	Mar-03	672.5	601.3	952.8	698.4	1,360.2	2,205.1	1,488.2	226.9	585.2	1,670.4
4	Apr-03	647.2	466.7	791.6	492.7	1,105.8	1,822.0	1,308.8	152.1	368.3	1,385.6
5	May-03	538.4	236.3	188.0	164.8	722.8	749.1	971.4	48.1	151.1	799.3
6	Jun-03	396.5	188.9	215.9	76.8	562.0	431.4	727.5	14.5	147.8	487.0
7	Jul-03	261.4	141.0	0.2	-	71.9	-	445.9	-	70.8	196.9
8	Aug-03	193.4	121.9	-	-	54.2	-	401.6	-	17.5	1.6
9	Sep-03	173.8	124.4	-	-	49.5	-	397.3	-	20.2	4.4
10	Oct-03	319.0	207.0	137.3	-	328.8	-	564.2	6.3	56.5	175.0
11	Nov-03	390.9	257.4	284.2	172.2	546.9	514.2	934.3	42.7	139.5	516.4
12	Dec-03	738.8	532.8	876.3	594.2	1,162.0	1,947.2	1,342.2	156.0	619.0	1,445.2
13	TOTAL	5,646.7	4,022.5	5,199.9	3,350.9	8,508.1	11,959.7	11,632.7	1,073.3	3,285.2	9,800.7

Source:
Lines 1-12: Response to Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Usage Analysis
Rate 81 Small Interruptible Transportation
Test Year Ending December 31, 2003

Rate 810 Customer Usage by Month - DekaTherms

Line		Customer ID Nos.						
No.	Month	191	252	125	218	34	33	Total
1	Jan-03	969.9	132.5	1,512.0	451.8	2,607.3	4,315.9	19,292.9
2	Feb-03	1,060.7	255.6	1,684.2	491.9	3,196.0	5,035.8	22,326.6
3	Mar-03	1,062.2	223.7	1,624.3	475.2	3,968.5	4,856.7	22,671.6
4	Apr-03	1,043.6	121.0	1,497.6	405.5	2,478.9	4,051.1	18,138.5
5	May-03	821.8	31.4	1,135.2	301.4	955.6	1,947.7	9,762.4
6	Jun-03	755.3	9.2	985.8	251.6	559.3	970.5	6,780.0
7	Jul-03	518.6	-	821.2	206.4	362.2	74.9	3,171.4
8	Aug-03	354.2	-	638.6	141.2	1,860.3	38.2	3,822.7
9	Sep-03	339.5	-	677.1	133.3	2,221.2	39.8	4,180.5
10	Oct-03	532.4	3.6	945.6	210.2	975.6	925.8	5,387.3
11	Nov-03	608.4	22.5	1,000.9	257.7	1,116.0	1,824.7	8,628.9
12	Dec-03	867.5	158.3	1,435.4	437.1	2,640.6	4,953.4	19,906.0
13	TOTAL	8,934.1	957.8	13,957.9	3,763.3	22,941.5	29,034.5	**144,068.8**

Source:
Lines 1-12: Response to Data Request No. 1-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Large Interruptible Transportation Service - Rate 82
Test Year Ending December 31, 2003

WEATHER STATION: *Rapid City*
REVENUE CLASS : LARGE INTERRUPTIBLE TRANSPORTATION GAS SERVICE - CUSTOMER ID 41

LINE NO.	(A) MONTH	(B) YEAR	(C) NUMBER OF CUSTOMERS	(D) DkT SALES	(E) BASE LOAD SALES (DkT)	(F) TEMP. SENSITIVE SALES (DkT)	(G) NORMAL HEATING DD	(H) ACTUAL HEATING DD	(I) NORMALIZATION FACTOR	(J) NORMALIZED TEMP. SENSITIVE SALES (DkT)	(K) NORMALIZED TOTAL SALES (DkT)	(L) WEATHER ADJUSTMENT (DkT)
1	JAN	2003	1	6,278.2	1,579.1	4,699.1	1,233	1,027	1.20058	5,642	7,221	943
2	FEB	2003	1	6,989.7	1,579.1	5,410.6	1,314	1,209	1.08685	5,881	7,460	470
3	MAR	2003	1	6,801.5	1,579.1	5,222.4	1,061	1,212	0.87541	4,572	6,151	(651)
4	APR	2003	1	5,711.6	1,579.1	4,132.5	925	924	1.00108	4,137	5,716	4
5	MAY	2003	1	3,550.0	1,579.1	1,970.9	595	505	1.17822	2,322	3,901	351
6	JUN	2003	1	2,646.0	1,579.1	1,066.9	313	320	0.97813	1,044	2,623	(23)
7	JUL	2003	1	1,708.6	1,708.6	-	88	134	0.00000	-	1,709	-
8	AUG	2003	1	1,479.5	1,479.5	-	16	-	0.00000	-	1,480	-
9	SEP	2003	1	1,549.1	1,549.1	-	21	17	0.00000	-	1,549	-
10	OCT	2003	1	2,244.2	1,579.1	665.1	190	220	0.86364	574	2,154	(91)
11	NOV	2003	1	3,684.5	1,579.1	2,105.4	521	385	1.35325	2,849	4,428	744
12	DEC	2003	1	6,324.8	1,579.1	4,745.7	934	1,087	0.85925	4,078	5,657	(668)
13		SUBTOTAL	12	48,967.7	18,948.8	30,018.9				31,098	50,047	1,079

Sources:
Column (C) and (D): Exhibit____(MCB-4) Schedule 1-2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
Column (G) and (H): Exhibit____(MCB-8)
Column (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Rate 82
Test Year Ending December 31, 2003

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO
LARGE INTERRUPTIBLE TRANSPORTATION GAS SERVICE - RATE 82

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMERS (E)	DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	DEC	2002	1,233	1,027	N/A	N/A	
2	JAN	2003	1,314	1,198	1	6,278.2	5,429.1667
3	FEB	2003	1,061	1,213	1	6,989.7	6,530.9000
4	MAR	2003	925	924	1	6,801.5	6,689.8000
5	APR	2003	595	505	1	5,711.6	6,500.9333
6	MAY	2003	313	320	1	3,550.0	5,354.3667
7	JUN	2003	88	54	1	2,646.0	3,969.2000
8	JUL	2003	16	-	1	1,708.6	2,634.8667
9	AUG	2003	21	17	1	1,479.5	1,944.7000
10	SEP	2003	190	65	1	1,549.1	1,579.0667
11	OCT	2003	521	385	1	2,244.2	1,757.6000
12	NOV	2003	934	1,087	1	3,684.5	2,492.6000
13	DEC	2003	1,233	1,063	1	6,324.8	4,084.5000
14			7,211	6,831	12	48,967.7	

Sources:

Column (C): NOAA Monthly Station Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1971 - 2000 for South Dakota, *Climatography of the United States No. 81*
Column (D): NOAA Climatological Data for South Dakota Volume 108 Number 1 to Volume 108 Number 12
Columns (E) and (F): MDU Response to Staff Data Request No. 1-4

MONTANA-DAKOTA UTILITIES
REVENUE INCREASE
COMPARISON

LINE NO.	BASE RATE REVENUE INCREASE by CUSTOMER CLASS	Dekatherms	Dekatherms	Test Year Revenue (Current Rates)	Proposed Revenue	Revenue (Inc./Dec.)	Percent (Inc./Dec.)
1	RESIDENTIAL	3,035,759	3,035,759	$7,683,206	$7,770,393	$87,187	1.1%
2	FIRM GENERAL SERVICE	2,076,428	2,076,428	2,984,424	3,101,055	116,631	3.9%
3	FIRM CONTRACT SERVICE	641,741	641,741	225,126	225,126	0	0.0%
4	ELLSWORTH AIR FORCE BASE	550,146	550,146	35,249	35,249	0	0.0%
5	INTERRUPTIBLE	110,220	110,220	32,377	33,202	824	2.5%
6	INTERRUPTIBLE TRANSPORT	889,088	889,088	319,573	325,434	5,860	1.8%
7	TOTAL	7,303,382	7,303,382	$11,279,955	$11,490,457	$210,502	1.9%

Source:
Line 1 - 5: Exhibit____(MCB-5) Schedule 2, 3, and 4

Montana-Dakota Utilities
South Dakota Gas
Residential Rates
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	CHANGE AMOUNT
	Small Meter									
	Residential - Rate 600									
1		ALL	DekaTherms	3,048,371	3,048,371	$ 1.43500	$ 1.46372	4,374,412	4,461,962	87,549
2										
3			Daily Charge			$ 0.25	$ 0.25			
4		CUSTOMER CHARGE	BILL	437,509	437,509	7.60	7.60	3,326,891	3,326,891	0
5										
6		PURCHASED GAS ADJUSTMENT				0.00000	0.00000			
7		SUB TOTAL	DekaTherms	3,048,371	3,048,371			7,701,304	7,788,853	87,549
8										
9	Residential Rate Unbilled Normalization									
10										
11		ALL	DekaTherms	(66,559)	(66,559)	1.43500	1.46372	(95,512)	(97,424)	(1,912)
12										
13		CUSTOMER CHARGE	BILL	0	0	7.60	7.60	0	0	0
14										
15		SUB TOTAL	DekaTherms	(66,559)	(66,559)			(95,512)	(97,424)	(1,912)
16										
17	Residential Rate Weather									
18										
19		ALL	DekaTherms	53,947	53,947	1.43500	1.46372	77,414	78,963	1,549
20										
21		CUSTOMER CHARGE	BILL	0	0	7.60	7.60	0	0	0
22										
23		PURCHASED GAS ADJUSTMENT				0.00000	0.00000			
24		SUB TOTAL	DekaTherms	53,947	53,947			77,414	78,963	1,549
25										
26	**TOTAL RESIDENTIAL - RATE 600**			**3,035,759**	**3,035,759**			**$ 7,683,206**	**$ 7,770,393**	**$ 87,187**
27										
28										

Montana-Dakota Utilities
South Dakota - Gas
Firm General Service Rates
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	CHANGE AMOUNT
	Small Meter									
	Firm General Service - Rate 700									
1		ALL	DekaTherms	505,166	505,166	$ 1.07810	$ 1.11250	544,619	561,997	17,378
2										
3			Daily Charge			$ 0.33	$ 0.35			
4		CUSTOMER CHARGE	BILL	42,548	42,548	10.04	10.65	427,076	452,959	25,883
5										
6										
7		SUB TOTAL	DekaTherms	505,166	505,166			971,695	1,014,956	43,261
8										
9	SMFG Rate Unbilled Normalization									
10										
11		ALL	DekaTherms	(13,887)	(13,887)	1.07810	1.11250	(14,972)	(15,450)	(478)
12										
13		CUSTOMER CHARGE	BILL	0	0	10.04	10.65	0	0	0
14										
15		SUB TOTAL	DekaTherms	(13,887)	(13,887)			(14,972)	(15,450)	(478)
16										
17	SMFG Rate Weather Normalization									
18										
19		ALL	DekaTherms	7,985	7,985	1.07810	1.11250	8,608	8,883	275
20										
21		CUSTOMER CHARGE	BILL	0	0	10.04	10.65	0	0	0
22										
23		SUB TOTAL		7,985	7,985			8,608	8,883	275

Montana-Dakota Utilities
South Dakota - Gas
Firm General Service Rates
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	CHANGE AMOUNT
24										
25	Reclassify Rate 71 as Rate 70									
26										
27		ALL	DekaTherms	9,941	9,941	1.07810	1.11250	10,717	11,059	342
28										
29		CUSTOMER CHARGE	BILL	0	0	10.04	10.65	0	0	0
30										
31	SUB TOTAL - PER BOOKS			9,941	9,941			10,717	11,059	342
32										
33	***TOTAL FIRM GENERAL SERVICE - RATE 700***			***509,204***	***509,204***			**976,049**	**1,019,449**	**$ 43,400**
34										
35	**Lage Meter**									
36	**Firm General Service - Rate 701**									
37										
38										
39		ALL	DekaTherms	1,575,717	1,575,717	$ 1.07810	$ 1.11250	1,698,780	1,752,985	54,205
40										
41			Daily Charge			$ 0.66	$ 0.70	per day		
42		CUSTOMER CHARGE	BILL	15,878	15,878	20.08	21.29	318,751	338,069	19,318
43										
44										
45	SUB TOTAL			1,575,717	1,575,717			2,017,531	2,091,054	73,523
46										
47	LMFG Rate Unbilled Normalization									
48										
49		ALL	DekaTherms	(29,443)	(29,443)	1.07810	1.11250	(31,742)	(32,755)	(1,013)
50										
51		CUSTOMER CHARGE	BILL	0	0	20.08	21.29	0	0	0
52										
53	SUB TOTAL - PER BOOKS			(29,443)	(29,443)			(31,742)	(32,755)	(1,013)
54										
55	LMFG Rate Weather Normalization									
56										
57		ALL	DekaTherms	20,950	20,950	1.07810	1.11250	22,586	23,307	721
58										
59		CUSTOMER CHARGE	BILL	0	0	20.08	21.29	0	0	0
60										
61										
62	SUB TOTAL			20,950	20,950			22,586	23,307	721
63										
64	**TOTAL FIRM GENERAL SERVICE - RATE 701**			**1,567,224**	**1,567,224**			**2,008,375**	**2,081,606**	**73,231**
65										
66	**TOTAL FIRM GENERAL SERVICE**			**2,076,428**	**2,076,428**			**$ 2,984,424**	**$ 3,101,055**	**$ 116,631**

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
	Firm Contract Service - Rate 702										
1		MIN BILLS	BILL			150.00	150.00				
2		MIN BILLS									
3		ALL	DekaTherms	639,787	639,787	0.34800	0.34800	222,646	222,646	0	
4											
5	CUSTOMER CHARGE & MINNUM		BILL	12	12	150.00	150.00	1,800	1,800	0	
6											
7	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
8		SUBTOTAL	DekaTherms	639,787	639,787			224,446	224,446	0	
9											
10	Firm Contract Service - Rate 702 - Weather Normalization										
11											
12		MIN BILLS	BILL			150.00	150.00				
13		MIN BILLS									
14		ALL	DekaTherms	1,954	1,954	0.34800	0.34800	680	680	0	
15											
16	CUSTOMER CHARGE & MINNUM		BILL	0	0	150.00	150.00	0	0	0	
17											
18	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
19		SUBTOTAL	DekaTherms	1,954	1,954			680	680	0	
20											
21	**TOTAL - Firm Contract Service - Rate 702**			**641,741**	**641,741**			**$ 225,126**	**$ 225,126**	**$ -**	**0.0%**
22											

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
23	**Ellsworth Air Force Base - Rate 641**										
24											
25		MIN BILLS	BILL			95.00	95.00				
26		MIN BILLS									
27		ALL	DekaTherms	537,378	537,378	0.06200	0.06200	33,317	33,317	0	
28											
29	CUSTOMER CHARGE & MINNUM		BILL	12	12	95.00	95.00	1,140	1,140	0	
30											
31	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
32		SUBTOTAL	DekaTherms	537,378	537,378			34,457	34,457	0	
33											
34	EAFB - Weather Normalization										
35											
36		MIN BILLS	BILL			95.00	95.00				
37		MIN BILLS									
38		ALL	DekaTherms	12,768	12,768	0.06200	0.06200	792	792	0	
39											
40	CUSTOMER CHARGE & MINNUM		BILL	0	0	95.00	95.00	0	0	0	
41											
42	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
43		SUBTOTAL	DekaTherms	12,768	12,768			792	792	0	
44											
45	**TOTAL - ELLSWORTH AIR FORCE BASE - RATE 641**			**550,146**	**550,146**			**$ 35,249**	**$ 35,249**	**$ -**	**0.0%**
46											

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
47	Small Interruptible - Rate 71										
48											
49		MIN BILLS	BILL			50.00	50.00				
50											
51		ALL	DekaTherms	35,076	35,076	0.45300	0.45549	15,889	15,977	87	
52											
53	CUSTOMER CHARGE & MINNUM		BILL	119	119	50.00	50.00	5,950	5,950	0	
54											
55	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
56		SUBTOTAL	DekaTherms	35,076	35,076			21,839	21,927	87	
57											
58	Small Interruptible Rate Unbilled Normalization										
59											
60		ALL THERMS	DekaTherms	(2,774)	(2,774)	0.45300	0.45549	(1,257)	(1,264)	(7)	
61											
62											
63	CUSTOMER CHARGE & MINNUM		BILL	0	0	50.00	50.00	0	0	0	
64											
65		SUB TOTAL	DekaTherms	(2,774)	(2,774)			(1,257)	(1,264)	(7)	
66											
58	Small Interruptible - Rate 71 - Weather Normalization										
59											
60		MIN BILLS	BILL			50.00	50.00				
61											
62		ALL	DekaTherms	531	531	0.45300	0.45549	241	242	1	
63											
64	CUSTOMER CHARGE & MINNUM		BILL	0	0	50.00	50.00	0	0	0	
65											
66	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
67		SUBTOTAL	DekaTherms	531	531			241	242	1	
68											
69	Small Interruptible - Rate 71 - Reclassify as Rate 70										
70											
71		MIN BILLS	BILL			50.00	50.00				
72											
73		ALL	DekaTherms	(9,941)	(9,941)	0.45300	0.45549	(4,503)	(4,528)	(25)	
74											
75	CUSTOMER CHARGE & MINNUM		BILL	(30)	(30)	50.00	50.00	(1,500)	(1,500)	0	
76											
77	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
78		SUBTOTAL	DekaTherms	(9,941)	(9,941)			(6,003)	(6,028)	(25)	
79	RATE 71 FLEX ADJUSTMENT							(421)	(424)	(3)	
80	TOTAL - SMALL INTERRUPTIBLE - RATE 71			22,892	22,892			14,820	14,877	57	0.4%

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
81											
82	**Large Interruptible - Rate 85**										
83											
84		MIN BILLS	BILL			150.00	175.00				
85		MIN BILLS									
86		ALL	DekaTherms	86,205	86,205	0.17700	0.18192	15,258	15,682	424	
87											
88	CUSTOMER CHARGE & MINNUM		BILL	14	14	150.00	175.00	2,100	2,450	350	
89											
90	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
91		SUBTOTAL	DekaTherms	86,205	86,205			17,358	18,132	774	
92											
93	Large Interruptible - Rate 85 - Weather Normalization										
94											
95		MIN BILLS	BILL			150.00	175.00				
96		MIN BILLS									
97		ALL	DekaTherms	1,123	1,123	0.17700	0.18192	199	204	6	
98											
99	CUSTOMER CHARGE & MINNUM		BILL	0	0	150.00	175.00	0	0	0	
100											
101	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
102		SUBTOTAL	DekaTherms	1,123	1,123			199	204	6	
103											
104	**TOTAL - LARGE INTERRUPTIBLE - RATE 85**			**87,328**	**87,328**			**17,557**	**18,337**	**$ 780**	**4.4%**
105											
106	**TOTAL - INTERRUPTIBLE**			**110,220**	**110,220**			**$ 32,377**	**$ 33,214**	**$ 837**	**2.6%**
107											

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
108	**Small Interruptible Transportion - Rate 81**										
109											
110		MIN BILLS	BILL			125.00	125.00				
111		MIN BILLS									
112		ALL	DekaTherms	354,602	354,602	0.45300	0.45549	160,635	161,518	883	
113											
114	CUSTOMER CHARGE & MINNUM		BILL	336	336	125.00	125.00	42,000	42,000	0	
115											
116	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
117		SUBTOTAL	DekaTherms	354,602	354,602			202,635	203,518	883	
118											
119	Small Interruptible Transportion - Rate 81 - Weather Normalization										
120											
121		MIN BILLS	BILL			125.00	125.00				
122		MIN BILLS									
123		ALL	DekaTherms	6,226	6,226	0.45300	0.45549	2,820	2,836	16	
124											
125	CUSTOMER CHARGE & MINNUM		BILL	0	0	125.00	125.00	0	0	0	
126											
127	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
128		SUBTOTAL	DekaTherms	6,226	6,226			2,820	2,836	16	
129											
130	Small Interruptible Transportation - Rate 81 - Cut Out of Service										
131											
132		MIN BILLS	BILL			125.00	125.00				
133		MIN BILLS									
134		ALL	DekaTherms	(5,282)	(5,282)	0.45300	0.45549	(2,393)	(2,406)	(13)	
135											
136	CUSTOMER CHARGE & MINNUM		BILL	(2)	(2)	125.00	125.00	(250)	(250)	0	
137											
138	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
139		SUBTOTAL	DekaTherms	(5,282)	(5,282)			(2,643)	(2,656)	(13)	
140											

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
141	CUSTOMER BILLED INCORRECTLY		Customer ID 41								
142											
143		MIN BILLS	BILL			125.00	125.00				
144		MIN BILLS									
145		ALL	DekaTherms	(10,225)	(10,225)	0.45300	0.45549	(4,632)	(4,657)	(25)	
146											
147	CUSTOMER CHARGE & MINNUM		BILL	(1)	(1)	125.00	125.00	(125)	(125)	0	
148											
149	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
150		SUBTOTAL	DekaTherms	(10,225)	(10,225)			(4,757)	(4,782)	(25)	
151											
152	Small Interruptible Transportation - Rate 82 - Reclassify as Rate 81										
153											
154		MIN BILLS	BILL			125.00	125.00				
155		MIN BILLS									
156		ALL	DekaTherms	10,403	10,403	0.45300	0.45549	4,713	4,738	26	
157											
158	CUSTOMER CHARGE & MINNUM		BILL	24	24	125.00	125.00	3,000	3,000	0	
159											
160	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
161		SUBTOTAL	DekaTherms	10,403	10,403			7,713	7,738	26	
162	RATE 81 FLEX ADJUSTMENT		Customer ID 264					(2,608)	(2,652)	(44)	
163	RATE 81 FLEX ADJUSTMENT		Customer ID 105					(1,555)	(1,574)	(19)	
164	TOTAL - SMALL INTERRUPTIBLE TRANSPORTATION - RATE 81			355,724	355,724			$ 205,768	$ 206,654	886	0.4%

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
165											
166	**Large Interruptible Transportation - Rate 82**										
167											
168		MIN BILLS	BILL			200.00	225.00				
169		MIN BILLS									
170		ALL	DekaTherms	613,766	613,766	0.17700	0.18192	108,637	111,656	3,020	
171											
172	CUSTOMER CHARGE & MINNUM		BILL	139	139	200.00	225.00	27,800	31,275	3,475	
173											
174	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
175		SUBTOTAL	DekaTherms	613,766	613,766			136,437	142,931	6,495	
176											
177	Large Interruptible Transportion - Customer ID 41 - Weather Normalization										
178											
179		MIN BILLS	BILL			200.00	225.00				
180		MIN BILLS									
181		ALL	DekaTherms	1,079	1,079	0.17700	0.18192	191	196	5	
182											
183	CUSTOMER CHARGE & MINNUM		BILL	0	0	200.00	225.00	0	0	0	
184											
185	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
186		*SUBTOTAL*	*DekaTherms*	1,079	1,079			191	196	5	
187											
188	CUSTOMER BILLED INCORRECTLY		Customer ID 41								
189											
190		MIN BILLS	BILL			200.00	225.00				
191		MIN BILLS									
192		ALL	DekaTherms	(10,225)	(10,225)	0.17700	0.18192	(1,810)	(1,860)	(50)	
193											
194	CUSTOMER CHARGE & MINNUM		BILL	(1)	(1)	200.00	225.00	(200)	(225)	(25)	
195											
196	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
197		SUBTOTAL	DekaTherms	(10,225)	(10,225)			(2,010)	(2,085)	(75)	
198											

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
199	Large Interruptible Transportation - Rate 82 - Cut Out of Service										
200											
201		MIN BILLS	BILL			200.00	225.00				
202		MIN BILLS									
203		ALL	DekaTherms	(60,853)	(60,853)	0.17700	0.18192	(10,771)	(11,070)	(299)	
204											
205	CUSTOMER CHARGE & MINNUM		BILL	(17)	(17)	200.00	225.00	(3,400)	(3,825)	(425)	
206											
207	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
208		SUBTOTAL	DekaTherms	(60,853)	(60,853)			(14,171)	(14,895)	(724)	
209											
210	Large Interruptible Transportation - Rate 82 - Reclassify as Rate 81										
211											
212		MIN BILLS	BILL			200.00	225.00				
213		MIN BILLS									
214		ALL	DekaTherms	(10,403)	(10,403)	0.17700	0.18192	(1,841)	(1,893)	(51)	
215											
216	CUSTOMER CHARGE & MINNUM		BILL	(24)	(24)	200.00	225.00	(4,800)	(5,400)	(600)	
217											
218	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
219		SUBTOTAL	DekaTherms	(10,403)	(10,403)			(6,641)	(7,293)	(651)	
220											
221	**TOTAL - LARGE INTERRUPTIBLE TRANSPORTATION - RATE 82**			**533,364**	**533,364**			**$ 113,805**	**$ 118,855**	**$ 5,049**	**4.4%**
222											
223	**TOTAL - INTERRUPTIBLE TRANSPORTATION**			**889,088**	**889,088**			**$ 319,573**	**$ 325,508**	**$ 5,935**	**1.9%**

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
1	CUSTOMER CHARGE	$7.60	$7.60
2	ALL DEKATHERMS	$1.43500	$1.46372
3	PGA	$6.97600	$6.97600

Rate 600 **RESIDENTIAL**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
4	0	$7.60	$7.60	$0.00	0.0%
5	1	16.02	16.04	0.03	0.2%
6	2	24.43	24.48	0.06	0.2%
7	3	32.84	32.92	0.09	0.3%
8	4	41.25	41.36	0.11	0.3%
9	5	49.66	49.80	0.14	0.3%
10	6	58.07	58.24	0.17	0.3%
11	7	66.48	66.68	0.20	0.3%
12	8	74.89	75.12	0.23	0.3%
13	9	83.30	83.56	0.26	0.3%
14	10	91.71	92.00	0.29	0.3%
15	12	108.54	108.88	0.34	0.3%
16	15	133.77	134.20	0.43	0.3%
17	20	175.82	176.40	0.57	0.3%
18	25	217.88	218.60	0.72	0.3%
19	30	259.93	260.80	0.86	0.3%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	15.4	136.73	137.18	0.44	0.3%
FEB	12.9	115.77	116.14	0.37	0.3%
MAR	10.9	99.00	99.31	0.31	0.3%
APR	8.7	80.55	80.80	0.25	0.3%
MAY	5.6	45.73	45.90	0.16	0.4%
JUN	3.1	30.18	30.26	0.09	0.3%
JUL	2.2	25.89	25.95	0.06	0.2%
AUG	1.6	20.44	20.49	0.05	0.2%
SEP	2.0	22.32	22.38	0.06	0.3%
OCT	3.7	35.94	36.05	0.11	0.3%
NOV	7.4	61.65	61.86	0.21	0.3%
DEC	11.4	90.86	91.19	0.33	0.4%
TOTAL	84.9	$765.07	$767.51	$2.44	0.3%

AVERAGE MONTHLY USE = 7.0 DekaTherms

Source:
Exhibit (MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
20	CUSTOMER CHARGE	$10.04	$10.65
21	ALL DEKATHERMS	$1.07810	$1.11250
22	PGA	$6.97600	$6.97600

Rate 700 **SMALL METER FIRM GENERAL SERVICE**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
23	0	10.04	10.65	$0.61	6.1%
24	5	50.31	51.09	0.78	1.6%
25	10	90.58	91.53	0.95	1.1%
26	15	130.85	131.97	1.12	0.9%
27	20	171.12	172.42	1.30	0.8%
28	30	251.66	253.30	1.64	0.7%
29	40	332.20	334.19	1.98	0.6%
30	50	412.74	415.07	2.33	0.6%
31	60	493.28	495.96	2.67	0.5%
32	70	573.82	576.84	3.02	0.5%
33	80	654.37	657.73	3.36	0.5%
34	90	734.91	738.61	3.70	0.5%
35	100	815.45	819.50	4.05	0.5%
36	150	1,218.15	1,223.92	5.77	0.5%
37	200	1,620.86	1,628.35	7.49	0.5%
38	250	2,023.56	2,032.77	9.21	0.5%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	27.9	234.75	236.31	1.57	0.7%
FEB	24.5	207.36	208.81	1.45	0.7%
MAR	21.0	179.17	180.50	1.33	0.7%
APR	14.1	123.60	124.69	1.09	0.9%
MAY	7.9	73.66	74.54	0.88	1.2%
JUN	4.2	43.86	44.62	0.75	1.7%
JUL	3.0	34.20	34.91	0.71	2.1%
AUG	2.5	30.17	30.87	0.69	2.3%
SEP	2.6	30.98	31.68	0.70	2.3%
OCT	4.5	46.28	47.04	0.76	1.6%
NOV	12.2	108.30	109.33	1.03	0.9%
DEC	19.8	169.51	170.80	1.29	0.8%
TOTAL	144.2	$1,281.85	$1,294.11	$12.26	1.0%

39 AVERAGE MONTHLY USE = 12.0 DekaTherms

Source:
Exhibit (MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
40	CUSTOMER CHARGE	$20.08	$21.29
41	ALL DEKATHERMS	$1.07810	$1.11250
42	PGA	$6.97600	$6.97600

Rate 701 **LARGE METER FIRM GENERAL SERVICE**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
43	0	20.08	21.29	$1.22	6.1%
44	5	60.35	61.73	1.39	2.3%
45	10	100.62	102.18	1.56	1.6%
46	15	140.89	142.62	1.73	1.2%
47	20	181.16	183.06	1.90	1.1%
48	30	261.70	263.95	2.25	0.9%
49	40	342.24	344.83	2.59	0.8%
50	50	422.78	425.72	2.94	0.7%
51	60	503.32	506.60	3.28	0.7%
52	70	583.86	587.49	3.62	0.6%
53	80	664.40	668.37	3.97	0.6%
54	90	744.94	749.26	4.31	0.6%
55	100	825.49	830.14	4.66	0.6%
56	150	1,228.19	1,234.57	6.38	0.5%
57	200	1,630.90	1,638.99	8.10	0.5%
58	250	2,033.60	2,043.42	9.82	0.5%
59	300	2,436.31	2,447.84	11.54	0.5%
60	350	2,839.01	2,852.27	13.26	0.5%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	197.7	1,612.37	1,620.39	$8.02	0.5%
FEB	172.1	1,406.19	1,413.32	$7.14	0.5%
MAR	154.1	1,261.21	1,267.73	$6.52	0.5%
APR	118.8	976.90	982.21	$5.30	0.5%
MAY	79.2	657.96	661.90	$3.94	0.6%
JUN	55.2	464.66	467.78	$3.12	0.7%
JUL	41.8	356.74	359.39	$2.65	0.7%
AUG	35.2	303.58	306.01	$2.43	0.8%
SEP	36.1	310.83	313.29	$2.46	0.8%
OCT	59.0	495.27	498.51	$3.25	0.7%
NOV	104.5	861.73	866.54	$4.81	0.6%
DEC	151.6	1,241.08	1,247.51	$6.43	0.5%
TOTAL	1,205.3	$9,948.51	$10,004.57	$56.06	0.6%

61 AVERAGE MONTHLY USE = *100.1 DekaTherms*

Source:
Exhibit (MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Interruptible and Transportation Service
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
	Firm Contract Service - Rate 702										
1		MIN BILLS	BILL			150.00	150.00				
2											
3		ALL	DekaTherms	641,741	641,741	0.34800	0.34800	223,326	223,326	0	
4											
5		CUSTOMER CHARGE & MINNUM	BILL	12	12	150.00	150.00	1,800	1,800	0	
6											
7		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			5.24100	5.24100	3,363,365	3,363,365	0	
8	**TOTAL - Firm Contract Service - Rate 702**			**641,741**	**641,741**			**$ 3,588,490**	**$ 3,588,490**	**$ -**	**0.0%**
9											
10	Ellsworth Air Force Base										
11											
12		MIN BILLS	BILL			95.00	95.00				
13											
14		ALL	DekaTherms	550,146	550,146	0.06200	0.06200	34,109	34,109	0	
15											
16		CUSTOMER CHARGE & MINNUM	BILL	12	12	95.00	95.00	1,140	1,140	0	
17											
18		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			3.95700	3.95700	2,176,928	2,176,928	0	
19	**TOTAL - Ellsworth Air Force Base**			**550,146**	**550,146**			**$ 2,212,177**	**$ 2,212,177**	**$ -**	**0.0%**
20											
21	Small Interruptible - Rate 71										
22											
23		MIN BILLS	BILL			50.00	50.00				
24											
25		ALL	DekaTherms	22,892	22,892	0.45300	0.45549	10,370	10,427	57	
26											
27		CUSTOMER CHARGE & MINNUM	BILL	119	119	50.00	50.00	5,950	5,950	0	
28											
29		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			5.24100	5.24100	119,977	119,977	0	
30	**TOTAL - SMALL INTERRUPTIBLE - RATE 71**			**22,892**	**22,892**			**$ 136,297**	**$ 136,354**	**$ 57**	**0.0%**
31											

Source: Exhibit____(MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Interruptible and Transportation Service
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
32	**Large Interruptible - Rate 85**										
33											
34		MIN BILLS	BILL			150.00	175.00				
35											
36		ALL	DekaTherms	87,328	87,328	0.17700	0.18192	15,457	15,887	430	
37											
38		CUSTOMER CHARGE & MINNUM	BILL	14	14	150.00	175.00	2,100	2,450	350	
39											
40		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			4.00200	4.00200	349,487	349,487	0	
41	**TOTAL - LARGE INTERRUPTIBLE - RATE 85**			**87,328**	**87,328**			**$ 367,044**	**$ 367,823**	**$ 780**	**0.2%**
42											
43	**Small Interruptible Transportion - Rate 81**										
44											
45		MIN BILLS	BILL			125.00	125.00				
46											
47		ALL	DekaTherms	355,724	355,724	0.45300	0.45549	161,143	162,029	886	
48											
49		CUSTOMER CHARGE & MINNUM	BILL	357	357	125.00	125.00	44,625	44,625	0	
50											
51		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			5.24100	5.24100	1,864,349	1,864,349	0	
52	**TOTAL - SMALL INTERRUPTIBLE TRANSPORTATION - RATE 81**			**355,724**	**355,724**			**$ 2,070,117**	**$ 2,071,003**	**$ 886**	**0.0%**
53											
54											
55	**Large Interruptible Transportation - Rate 82**										
56											
57		MIN BILLS	BILL			200.00	225.00				
58											
59		ALL	DekaTherms	533,364	533,364	0.17700	0.18192	94,405	97,030	2,624	
60											
61		CUSTOMER CHARGE & MINNUM	BILL	97	97	200.00	225.00	19,400	21,825	2,425	
62											
63		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			4.00200	4.00200	2,134,523	2,134,523	0	
64	**TOTAL - LARGE INTERRUPTIBLE TRANSPORTATION - RATE 82**			**533,364**	**533,364**			**$ 2,248,328**	**$ 2,253,377**	**$ 5,049**	**0.2%**
65											
66	**TOTAL - OTHER INTERRUPTIBLE and TRANSPORTATION**			**2,191,195**	**2,191,195**			**$ 10,622,454**	**$ 10,629,225**	**$ 6,772**	**0.1%**

Exhibit ____ (MCB-8)
Schedule 1
Pages 1 of 6

Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending DECEMBER 31, 2003

Revenue Month	Bill Cycle	Start Date	End Date	Min Of Date	Max Of Date	Count Of Date	Sum Of HDD 65 Actual	Sum Of HDD 65 Normal
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Jan 03	1	11/29/02	12/30/02	29-Nov-02	29-Dec-02	31	1013	1221
Jan 03	2	12/02/02	01/02/03	02-Dec-02	01-Jan-03	31	1041	1239
Jan 03	3	12/03/02	01/03/03	03-Dec-02	02-Jan-03	31	1046	1245
Jan 03	4	12/04/02	01/06/03	04-Dec-02	05-Jan-03	33	1081	1337
Jan 03	5	12/05/02	01/07/03	05-Dec-02	06-Jan-03	33	1050	1343
Jan 03	6	12/06/02	01/08/03	06-Dec-02	07-Jan-03	33	1024	1349
Jan 03	7	12/09/02	01/09/03	09-Dec-02	08-Jan-03	31	943	1278
Jan 03	8	12/10/02	01/10/03	10-Dec-02	09-Jan-03	31	956	1283
Jan 03	9	12/11/02	01/13/03	11-Dec-02	12-Jan-03	33	1066	1373
Jan 03	10	12/12/02	01/14/03	12-Dec-02	13-Jan-03	33	1079	1377
Jan 03	11	12/13/02	01/15/03	13-Dec-02	14-Jan-03	33	1097	1381
Jan 03	12	12/16/02	01/16/03	16-Dec-02	15-Jan-03	31	1081	1305
Jan 03	13	12/17/02	01/17/03	17-Dec-02	16-Jan-03	31	1114	1308
Jan 03	14	12/18/02	01/20/03	18-Dec-02	19-Jan-03	33	1206	1395
Jan 03	15	12/19/02	01/21/03	19-Dec-02	20-Jan-03	33	1220	1397
Jan 03	16	12/20/02	01/22/03	20-Dec-02	21-Jan-03	33	1247	1398
Jan 03	17	12/23/02	01/23/03	23-Dec-02	22-Jan-03	31	1191	1317
Jan 03	18	12/24/02	01/24/03	24-Dec-02	23-Jan-03	31	1201	1318
Jan 03	19	12/26/02	01/27/03	26-Dec-02	26-Jan-03	32	1255	1362
Jan 03	20	12/27/02	01/28/03	27-Dec-02	27-Jan-03	32	1238	1361
Jan 03 Average							**1107.5**	**1329.4**
Feb 03	1	12/30/02	01/29/03	30-Dec-02	28-Jan-03	30	1199	1276
Feb 03	2	01/02/03	02/03/03	02-Jan-03	02-Feb-03	32	1224	1353
Feb 03	3	01/03/03	02/04/03	03-Jan-03	03-Feb-03	32	1232	1350
Feb 03	4	01/06/03	02/05/03	06-Jan-03	04-Feb-03	30	1201	1261
Feb 03	5	01/07/03	02/06/03	07-Jan-03	05-Feb-03	30	1222	1258
Feb 03	6	01/08/03	02/07/03	08-Jan-03	06-Feb-03	30	1263	1255
Feb 03	7	01/09/03	02/10/03	09-Jan-03	09-Feb-03	32	1392	1330
Feb 03	8	01/10/03	02/11/03	10-Jan-03	10-Feb-03	32	1395	1326
Feb 03	9	01/13/03	02/12/03	13-Jan-03	11-Feb-03	30	1388	1322
Feb 03	10	01/14/03	02/13/03	14-Jan-03	12-Feb-03	30	1307	1318
Feb 03	11	01/15/03	02/14/03	15-Jan-03	13-Feb-03	30	1295	1313
Feb 03	12	01/16/03	02/17/03	16-Jan-03	16-Feb-03	32	1359	1298
Feb 03	13	01/17/03	02/18/03	17-Jan-03	17-Feb-03	32	1329	1292
Feb 03	14	01/20/03	02/19/03	20-Jan-03	18-Feb-03	30	1240	1202
Feb 03	15	01/21/03	02/20/03	21-Jan-03	19-Feb-03	30	1224	1197
Feb 03	16	01/22/03	02/21/03	22-Jan-03	20-Feb-03	30	1196	1192
Feb 03	17	01/23/03	02/24/03	23-Jan-03	23-Feb-03	32	1290	1258
Feb 03	18	01/24/03	02/25/03	24-Jan-03	24-Feb-03	32	1305	1252
Feb 03	19	01/27/03	02/26/03	27-Jan-03	25-Feb-03	30	1223	1161
Feb 03	20	01/28/03	02/27/03	28-Jan-03	26-Feb-03	30	1243	1155
Feb 03 Average							**1276.4**	**1268.5**
Mar 03	1	01/29/03	02/28/03	29-Jan-03	27-Feb-03	30	1257	1149
Mar 03	2	02/03/03	03/03/03	03-Feb-03	02-Mar-03	28	1246	1048

Sources:
Columns (A) through (G): Provided by Montana-Dakota Utilities

Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending DECEMBER 31, 2003

Revenue Month	Bill Cycle	Start Date	End Date	Min Of Date	Max Of Date	Count Of Date	Sum Of HDD 65 Actual	Sum Of HDD 65 Normal
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Mar 03	3	02/04/03	03/04/03	04-Feb-03	03-Mar-03	28	1246	1042
Mar 03	4	02/05/03	03/05/03	05-Feb-03	04-Mar-03	28	1256	1036
Mar 03	5	02/06/03	03/06/03	06-Feb-03	05-Mar-03	28	1254	1029
Mar 03	6	02/07/03	03/07/03	07-Feb-03	06-Mar-03	28	1234	1022
Mar 03	7	02/10/03	03/10/03	10-Feb-03	09-Mar-03	28	1242	1000
Mar 03	8	02/11/03	03/11/03	11-Feb-03	10-Mar-03	28	1233	993
Mar 03	9	02/12/03	03/12/03	12-Feb-03	11-Mar-03	28	1216	985
Mar 03	10	02/13/03	03/13/03	13-Feb-03	12-Mar-03	28	1202	977
Mar 03	11	02/14/03	03/14/03	14-Feb-03	13-Mar-03	28	1176	970
Mar 03	12	02/17/03	03/17/03	17-Feb-03	16-Mar-03	28	1094	946
Mar 03	13	02/18/03	03/18/03	18-Feb-03	17-Mar-03	28	1089	938
Mar 03	14	02/19/03	03/19/03	19-Feb-03	18-Mar-03	28	1088	930
Mar 03	15	02/20/03	03/20/03	20-Feb-03	19-Mar-03	28	1089	922
Mar 03	16	02/21/03	03/21/03	21-Feb-03	20-Mar-03	28	1087	914
Mar 03	17	02/24/03	03/24/03	24-Feb-03	23-Mar-03	28	976	890
Mar 03	18	02/25/03	03/25/03	25-Feb-03	24-Mar-03	28	928	881
Mar 03	19	02/26/03	03/26/03	26-Feb-03	25-Mar-03	28	896	873
Mar 03	20	02/27/03	03/27/03	27-Feb-03	26-Mar-03	28	871	865
Mar 03 Average							**1134.0**	**970.5**
Apr 03	1	02/28/03	03/28/03	28-Feb-03	27-Mar-03	28	862	857
Apr 03	2	03/03/03	04/01/03	03-Mar-03	31-Mar-03	29	839	856
Apr 03	3	03/04/03	04/02/03	04-Mar-03	01-Apr-03	29	802	847
Apr 03	4	03/05/03	04/03/03	05-Mar-03	02-Apr-03	29	773	837
Apr 03	5	03/06/03	04/04/03	06-Mar-03	03-Apr-03	29	753	828
Apr 03	6	03/07/03	04/07/03	07-Mar-03	06-Apr-03	31	806	865
Apr 03	7	03/10/03	04/08/03	10-Mar-03	07-Apr-03	29	678	792
Apr 03	8	03/11/03	04/09/03	11-Mar-03	08-Apr-03	29	665	782
Apr 03	9	03/12/03	04/10/03	12-Mar-03	09-Apr-03	29	652	773
Apr 03	10	03/13/03	04/11/03	13-Mar-03	10-Apr-03	29	638	764
Apr 03	11	03/14/03	04/14/03	14-Mar-03	13-Apr-03	31	638	796
Apr 03	12	03/17/03	04/15/03	17-Mar-03	14-Apr-03	29	605	726
Apr 03	13	03/18/03	04/16/03	18-Mar-03	15-Apr-03	29	592	717
Apr 03	14	03/19/03	04/17/03	19-Mar-03	16-Apr-03	29	580	708
Apr 03	15	03/20/03	04/18/03	20-Mar-03	17-Apr-03	29	566	698
Apr 03	16	03/21/03	04/21/03	21-Mar-03	20-Apr-03	31	597	725
Apr 03	17	03/24/03	04/22/03	24-Mar-03	21-Apr-03	29	559	659
Apr 03	18	03/25/03	04/23/03	25-Mar-03	22-Apr-03	29	546	650
Apr 03	19	03/26/03	04/24/03	26-Mar-03	23-Apr-03	29	536	640
Apr 03	20	03/27/03	04/25/03	27-Mar-03	24-Apr-03	29	536	630
Apr 03 Average							**661.2**	**757.5**
May 03	1	03/28/03	04/28/03	28-Mar-03	27-Apr-03	31	545	652
May 03	2	04/01/03	05/01/03	01-Apr-03	30-Apr-03	30	505	595
May 03	3	04/02/03	05/02/03	02-Apr-03	01-May-03	30	520	585
May 03	4	04/03/03	05/05/03	03-Apr-03	04-May-03	32	528	605

Sources:
Columns (A) through (G): Provided by Montana-Dakota Utilities
Column (H): Actual Number of HDDs in Billing Period

Exhibit ____ (MCB-8)
Schedule 1
Pages 3 of 6

Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending DECEMBER 31, 2003

Revenue Month	Bill Cycle	Start Date	End Date	Min Of Date	Max Of Date	Count Of Date	Sum Of HDD 65 Actual	Sum Of HDD 65 Normal
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
May 03	5	04/04/03	05/06/03	04-Apr-03	05-May-03	32	523	595
May 03	6	04/07/03	05/07/03	07-Apr-03	06-May-03	30	449	539
May 03	7	04/08/03	05/08/03	08-Apr-03	07-May-03	30	432	529
May 03	8	04/09/03	05/09/03	09-Apr-03	08-May-03	30	426	520
May 03	9	04/10/03	05/12/03	10-Apr-03	11-May-03	32	468	535
May 03	10	04/11/03	05/13/03	11-Apr-03	12-May-03	32	471	524
May 03	11	04/14/03	05/14/03	14-Apr-03	13-May-03	30	468	472
May 03	12	04/15/03	05/15/03	15-Apr-03	14-May-03	30	476	463
May 03	13	04/16/03	05/16/03	16-Apr-03	15-May-03	30	474	453
May 03	14	04/17/03	05/19/03	17-Apr-03	18-May-03	32	479	462
May 03	15	04/18/03	05/20/03	18-Apr-03	19-May-03	32	485	451
May 03	16	04/21/03	05/21/03	21-Apr-03	20-May-03	30	450	403
May 03	17	04/22/03	05/22/03	22-Apr-03	21-May-03	30	446	393
May 03	18	04/23/03	05/23/03	23-Apr-03	22-May-03	30	440	383
May 03	19	04/24/03	05/27/03	24-Apr-03	26-May-03	33	433	394
May 03	20	04/25/03	05/28/03	25-Apr-03	27-May-03	33	414	384
May 03 Average							**471.6**	**496.9**
Jun 03	1	04/28/03	05/29/03	28-Apr-03	28-May-03	31	372	341
Jun 03	2	05/01/03	06/02/03	01-May-03	01-Jun-03	32	331	319
Jun 03	3	05/02/03	06/03/03	02-May-03	02-Jun-03	32	316	310
Jun 03	4	05/05/03	06/04/03	05-May-03	03-Jun-03	30	288	272
Jun 03	5	05/06/03	06/05/03	06-May-03	04-Jun-03	30	278	263
Jun 03	6	05/07/03	06/06/03	07-May-03	05-Jun-03	30	270	254
Jun 03	7	05/08/03	06/09/03	08-May-03	08-Jun-03	32	293	254
Jun 03	8	05/09/03	06/10/03	09-May-03	09-Jun-03	32	280	245
Jun 03	9	05/12/03	06/11/03	12-May-03	10-Jun-03	30	229	212
Jun 03	10	05/13/03	06/12/03	13-May-03	11-Jun-03	30	216	204
Jun 03	11	05/14/03	06/13/03	14-May-03	12-Jun-03	30	209	196
Jun 03	12	05/15/03	06/16/03	15-May-03	15-Jun-03	32	200	192
Jun 03	13	05/16/03	06/17/03	16-May-03	16-Jun-03	32	193	184
Jun 03	14	05/19/03	06/18/03	19-May-03	17-Jun-03	30	169	157
Jun 03	15	05/20/03	06/19/03	20-May-03	18-Jun-03	30	148	151
Jun 03	16	05/21/03	06/20/03	21-May-03	19-Jun-03	30	126	145
Jun 03	17	05/22/03	06/23/03	22-May-03	22-Jun-03	32	116	143
Jun 03	18	05/23/03	06/24/03	23-May-03	23-Jun-03	32	116	137
Jun 03	19	05/27/03	06/25/03	27-May-03	24-Jun-03	29	123	111
Jun 03	20	05/28/03	06/26/03	28-May-03	25-Jun-03	29	133	106
Jun 03 Average							**220.3**	**209.8**
Jul 03	1	05/29/03	06/27/03	29-May-03	26-Jun-03	29	137	102
Jul 03	2	06/02/03	07/01/03	02-Jun-03	30-Jun-03	29	123	82
Jul 03	3	06/03/03	07/02/03	03-Jun-03	01-Jul-03	29	117	77
Jul 03	4	06/04/03	07/03/03	04-Jun-03	02-Jul-03	29	109	72
Jul 03	5	06/05/03	07/07/03	05-Jun-03	06-Jul-03	32	100	71
Jul 03	6	06/06/03	07/08/03	06-Jun-03	07-Jul-03	32	88	67

Sources:
Columns (A) through (G): Provided by Montana-Dakota Utilities

Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending DECEMBER 31, 2003

Revenue Month	Bill Cycle	Start Date	End Date	Min Of Date	Max Of Date	Count Of Date	Sum Of HDD 65 Actual	Sum Of HDD 65 Normal
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Jul 03	7	06/09/03	07/09/03	09-Jun-03	08-Jul-03	30	53	55
Jul 03	8	06/10/03	07/10/03	10-Jun-03	09-Jul-03	30	49	52
Jul 03	9	06/11/03	07/11/03	11-Jun-03	10-Jul-03	30	45	49
Jul 03	10	06/12/03	07/14/03	12-Jun-03	13-Jul-03	32	43	49
Jul 03	11	06/13/03	07/15/03	13-Jun-03	14-Jul-03	32	41	47
Jul 03	12	06/16/03	07/16/03	16-Jun-03	15-Jul-03	30	39	41
Jul 03	13	06/17/03	07/17/03	17-Jun-03	16-Jul-03	30	39	40
Jul 03	14	06/18/03	07/18/03	18-Jun-03	17-Jul-03	30	39	38
Jul 03	15	06/19/03	07/21/03	19-Jun-03	20-Jul-03	32	39	36
Jul 03	16	06/20/03	07/22/03	20-Jun-03	21-Jul-03	32	39	34
Jul 03	17	06/23/03	07/23/03	23-Jun-03	22-Jul-03	30	39	28
Jul 03	18	06/24/03	07/24/03	24-Jun-03	23-Jul-03	30	34	26
Jul 03	19	06/25/03	07/25/03	25-Jun-03	24-Jul-03	30	19	24
Jul 03	20	06/26/03	07/28/03	26-Jun-03	27-Jul-03	32	9	22
Jul 03 Average							**60.1**	**50.6**
Aug 03	1	06/27/03	07/29/03	27-Jun-03	28-Jul-03	32	5	20
Aug 03	2	07/01/03	08/01/03	01-Jul-03	31-Jul-03	31	0	16
Aug 03	3	07/02/03	08/04/03	02-Jul-03	03-Aug-03	33	0	15
Aug 03	4	07/03/03	08/05/03	03-Jul-03	04-Aug-03	33	0	14
Aug 03	5	07/07/03	08/06/03	07-Jul-03	05-Aug-03	30	0	10
Aug 03	6	07/08/03	08/07/03	08-Jul-03	06-Aug-03	30	0	9
Aug 03	7	07/09/03	08/08/03	09-Jul-03	07-Aug-03	30	0	8
Aug 03	8	07/10/03	08/11/03	10-Jul-03	10-Aug-03	32	0	7
Aug 03	9	07/11/03	08/12/03	11-Jul-03	11-Aug-03	32	0	6
Aug 03	10	07/14/03	08/13/03	14-Jul-03	12-Aug-03	30	0	3
Aug 03	11	07/15/03	08/14/03	15-Jul-03	13-Aug-03	30	0	2
Aug 03	12	07/16/03	08/15/03	16-Jul-03	14-Aug-03	30	0	1
Aug 03	13	07/17/03	08/18/03	17-Jul-03	17-Aug-03	32	0	1
Aug 03	14	07/18/03	08/19/03	18-Jul-03	18-Aug-03	32	0	2
Aug 03	15	07/21/03	08/20/03	21-Jul-03	19-Aug-03	30	0	3
Aug 03	16	07/22/03	08/21/03	22-Jul-03	20-Aug-03	30	0	4
Aug 03	17	07/23/03	08/22/03	23-Jul-03	21-Aug-03	30	0	5
Aug 03	18	07/24/03	08/25/03	24-Jul-03	24-Aug-03	32	0	8
Aug 03	19	07/25/03	08/26/03	25-Jul-03	25-Aug-03	32	0	9
Aug 03	20	07/28/03	08/27/03	28-Jul-03	26-Aug-03	30	0	11
Aug 03 Average							**0.3**	**7.7**
Sep 03	1	07/29/03	08/28/03	29-Jul-03	27-Aug-03	30	0	13
Sep 03	2	08/01/03	09/02/03	01-Aug-03	01-Sep-03	32	17	24
Sep 03	3	08/04/03	09/03/03	04-Aug-03	02-Sep-03	30	17	27
Sep 03	4	08/05/03	09/04/03	05-Aug-03	03-Sep-03	30	18	30
Sep 03	5	08/06/03	09/05/03	06-Aug-03	04-Sep-03	30	18	33
Sep 03	6	08/07/03	09/08/03	07-Aug-03	07-Sep-03	32	18	44
Sep 03	7	08/08/03	09/09/03	08-Aug-03	08-Sep-03	32	18	48
Sep 03	8	08/11/03	09/10/03	11-Aug-03	09-Sep-03	30	18	53

Sources:
Columns (A) through (G): Provided by Montana-Dakota Utilities
Column (H): Actual Number of HDDs in Billing Period

Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending DECEMBER 31, 2003

Revenue Month	Bill Cycle	Start Date	End Date	Min Of Date	Max Of Date	Count Of Date	Sum Of HDD 65 Actual	Sum Of HDD 65 Normal
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Sep 03	9	08/12/03	09/11/03	12-Aug-03	10-Sep-03	30	26	58
Sep 03	10	08/13/03	09/12/03	13-Aug-03	11-Sep-03	30	29	63
Sep 03	11	08/14/03	09/15/03	14-Aug-03	14-Sep-03	32	56	79
Sep 03	12	08/15/03	09/16/03	15-Aug-03	15-Sep-03	32	59	85
Sep 03	13	08/18/03	09/17/03	18-Aug-03	16-Sep-03	30	59	90
Sep 03	14	08/19/03	09/18/03	19-Aug-03	17-Sep-03	30	73	96
Sep 03	15	08/20/03	09/19/03	20-Aug-03	18-Sep-03	30	92	102
Sep 03	16	08/21/03	09/22/03	21-Aug-03	21-Sep-03	32	120	123
Sep 03	17	08/22/03	09/23/03	22-Aug-03	22-Sep-03	32	135	130
Sep 03	18	08/25/03	09/24/03	25-Aug-03	23-Sep-03	30	136	135
Sep 03	19	08/26/03	09/25/03	26-Aug-03	24-Sep-03	30	152	143
Sep 03	20	08/27/03	09/26/03	27-Aug-03	25-Sep-03	30	158	150
Sep 03 Average							**61.0**	**76.3**
Oct 03	1	08/28/03	09/29/03	28-Aug-03	28-Sep-03	32	199	178
Oct 03	2	09/02/03	10/01/03	02-Sep-03	30-Sep-03	29	220	187
Oct 03	3	09/03/03	10/02/03	03-Sep-03	01-Oct-03	29	238	194
Oct 03	4	09/04/03	10/03/03	04-Sep-03	02-Oct-03	29	249	202
Oct 03	5	09/05/03	10/06/03	05-Sep-03	05-Oct-03	31	266	233
Oct 03	6	09/08/03	10/07/03	08-Sep-03	06-Oct-03	29	266	234
Oct 03	7	09/09/03	10/08/03	09-Sep-03	07-Oct-03	29	266	243
Oct 03	8	09/10/03	10/09/03	10-Sep-03	08-Oct-03	29	269	251
Oct 03	9	09/11/03	10/10/03	11-Sep-03	09-Oct-03	29	261	259
Oct 03	10	09/12/03	10/13/03	12-Sep-03	12-Oct-03	31	293	297
Oct 03	11	09/15/03	10/14/03	15-Sep-03	13-Oct-03	29	282	296
Oct 03	12	09/16/03	10/15/03	16-Sep-03	14-Oct-03	29	300	306
Oct 03	13	09/17/03	10/16/03	17-Sep-03	15-Oct-03	29	320	316
Oct 03	14	09/18/03	10/17/03	18-Sep-03	16-Oct-03	29	328	326
Oct 03	15	09/19/03	10/20/03	19-Sep-03	19-Oct-03	31	313	372
Oct 03	16	09/22/03	10/21/03	22-Sep-03	20-Oct-03	29	288	368
Oct 03	17	09/23/03	10/22/03	23-Sep-03	21-Oct-03	29	273	379
Oct 03	18	09/24/03	10/23/03	24-Sep-03	22-Oct-03	29	272	390
Oct 03	19	09/25/03	10/24/03	25-Sep-03	23-Oct-03	29	265	401
Oct 03	20	09/26/03	10/27/03	26-Sep-03	26-Oct-03	31	332	455
Oct 03 Average							**275.0**	**294.4**
Nov 03	1	09/29/03	10/28/03	29-Sep-03	27-Oct-03	29	300	447
Nov 03	2	10/01/03	10/31/03	01-Oct-03	30-Oct-03	30	343	497
Nov 03	3	10/02/03	11/03/03	02-Oct-03	02-Nov-03	32	444	561
Nov 03	4	10/03/03	11/04/03	03-Oct-03	03-Nov-03	32	474	576
Nov 03	5	10/06/03	11/05/03	06-Oct-03	04-Nov-03	30	505	568
Nov 03	6	10/07/03	11/06/03	07-Oct-03	05-Nov-03	30	559	583
Nov 03	7	10/08/03	11/07/03	08-Oct-03	06-Nov-03	30	607	597
Nov 03	8	10/09/03	11/10/03	09-Oct-03	09-Nov-03	32	741	669
Nov 03	9	10/10/03	11/11/03	10-Oct-03	10-Nov-03	32	767	685
Nov 03	10	10/13/03	11/12/03	13-Oct-03	11-Nov-03	30	756	671

Sources:
Columns (A) through (G): Provided by Montana-Dakota Utilities

Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending DECEMBER 31, 2003

Revenue Month	Bill Cycle	Start Date	End Date	Min Of Date	Max Of Date	Count Of Date	Sum Of HDD 65 Actual	Sum Of HDD 65 Normal
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Nov 03	11	10/14/03	11/13/03	14-Oct-03	12-Nov-03	30	773	686
Nov 03	12	10/15/03	11/14/03	15-Oct-03	13-Nov-03	30	781	700
Nov 03	13	10/16/03	11/17/03	16-Oct-03	16-Nov-03	32	832	778
Nov 03	14	10/17/03	11/18/03	17-Oct-03	17-Nov-03	32	832	793
Nov 03	15	10/20/03	11/19/03	20-Oct-03	18-Nov-03	30	852	772
Nov 03	16	10/21/03	11/20/03	21-Oct-03	19-Nov-03	30	861	787
Nov 03	17	10/22/03	11/21/03	22-Oct-03	20-Nov-03	30	881	801
Nov 03	18	10/23/03	11/24/03	23-Oct-03	23-Nov-03	32	1036	883
Nov 03	19	10/24/03	11/25/03	24-Oct-03	24-Nov-03	32	1070	898
Nov 03	20	10/27/03	11/26/03	27-Oct-03	25-Nov-03	30	1042	870
Nov 03 Average							**722.8**	**691.1**
Dec 03	1	10/28/03	11/28/03	28-Oct-03	27-Nov-03	31	1114	919
Dec 03	2	10/31/03	12/01/03	31-Oct-03	30-Nov-03	31	1129	958
Dec 03	3	11/03/03	12/02/03	03-Nov-03	01-Dec-03	29	1041	921
Dec 03	4	11/04/03	12/03/03	04-Nov-03	02-Dec-03	29	1031	932
Dec 03	5	11/05/03	12/04/03	05-Nov-03	03-Dec-03	29	1013	943
Dec 03	6	11/06/03	12/05/03	06-Nov-03	04-Dec-03	29	993	953
Dec 03	7	11/07/03	12/08/03	07-Nov-03	07-Dec-03	31	1032	1039
Dec 03	8	11/10/03	12/09/03	10-Nov-03	08-Dec-03	29	930	992
Dec 03	9	11/11/03	12/10/03	11-Nov-03	09-Dec-03	29	943	1001
Dec 03	10	11/12/03	12/11/03	12-Nov-03	10-Dec-03	29	964	1011
Dec 03	11	11/13/03	12/12/03	13-Nov-03	11-Dec-03	29	987	1020
Dec 03	12	11/14/03	12/15/03	14-Nov-03	14-Dec-03	31	1080	1108
Dec 03	13	11/17/03	12/16/03	17-Nov-03	15-Dec-03	29	1045	1054
Dec 03	14	11/18/03	12/17/03	18-Nov-03	16-Dec-03	29	1057	1062
Dec 03	15	11/19/03	12/18/03	19-Nov-03	17-Dec-03	29	1060	1070
Dec 03	16	11/20/03	12/19/03	20-Nov-03	18-Dec-03	29	1080	1077
Dec 03	17	11/21/03	12/22/03	21-Nov-03	21-Dec-03	31	1136	1167
Dec 03	18	11/24/03	12/23/03	24-Nov-03	22-Dec-03	29	1013	1107
Dec 03	19	11/25/03	12/24/03	25-Nov-03	23-Dec-03	29	1000	1113
Dec 03	20	11/26/03	12/26/03	26-Nov-03	25-Dec-03	30	1012	1160
Dec 03 Average							**1033.0**	**1030.4**

Sources:
Columns (A) through (G): Provided by Montana-Dakota Utilities
Column (H): Actual Number of HDDs in Billing Period

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

	Temperature			
Date	Hi	Low	Avg	HDD-65
(A)	(B)	(C)	(D)	(E)
24-Nov-02	26	10	18	47
25-Nov-02	35	-2	17	48
26-Nov-02	23	10	17	48
27-Nov-02	41	16	29	36
28-Nov-02	68	27	48	17
29-Nov-02	51	30	41	24
30-Nov-02	44	16	30	35
01-Dec-02	63	23	43	22
02-Dec-02	46	24	35	30
03-Dec-02	28	15	22	43
04-Dec-02	16	1	9	56
05-Dec-02	36	2	19	46
06-Dec-02	48	18	33	32
07-Dec-02	43	22	33	32
08-Dec-02	40	15	28	37
09-Dec-02	50	21	36	29
10-Dec-02	60	21	41	24
11-Dec-02	52	30	41	24
12-Dec-02	46	20	33	32
13-Dec-02	58	20	39	26
14-Dec-02	53	27	40	25
15-Dec-02	62	30	46	19
16-Dec-02	53	28	41	24
17-Dec-02	46	26	36	29
18-Dec-02	45	25	35	30
19-Dec-02	42	30	36	29
20-Dec-02	40	19	30	35
21-Dec-02	32	11	22	43
22-Dec-02	32	4	18	47
23-Dec-02	32	4	18	47
24-Dec-02	35	6	21	44
25-Dec-02	38	9	24	41
26-Dec-02	39	8	24	41
27-Dec-02	54	20	37	28
28-Dec-02	60	34	47	18
29-Dec-02	61	27	44	21
30-Dec-02	42	14	28	37
31-Dec-02	45	13	29	36
01-Jan-03	44	14	29	36
02-Jan-03	48	11	30	35
03-Jan-03	59	28	44	21
04-Jan-03	51	25	38	27
05-Jan-03	43	26	35	30
06-Jan-03	57	22	40	25
07-Jan-03	63	27	45	20
08-Jan-03	58	31	45	20
09-Jan-03	33	13	23	42
10-Jan-03	25	4	15	50

Source:
Column (B) and (C): NOAA Climatological Data South Dakota Volume107 No. 11 to Volume 108 No.12
Column (D): (Column (B) + Column (C))/2

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

	Temperature			
Date	Hi	Low	Avg	HDD 65
(A)	(B)	(C)	(D)	(E)
11-Jan-03	28	4	16	49
12-Jan-03	52	8	30	35
13-Jan-03	53	3	28	37
14-Jan-03	27	2	15	50
15-Jan-03	14	8	11	54
16-Jan-03	18	-2	8	57
17-Jan-03	36	-4	16	49
18-Jan-03	31	11	21	44
19-Jan-03	55	18	37	28
20-Jan-03	30	11	21	44
21-Jan-03	12	5	9	56
22-Jan-03	5	-13	-4	69
23-Jan-03	22	-7	8	57
24-Jan-03	46	-11	18	47
25-Jan-03	38	1	20	45
26-Jan-03	34	1	18	47
27-Jan-03	52	30	41	24
28-Jan-03	46	28	37	28
29-Jan-03	43	21	32	33
30-Jan-03	49	26	38	27
31-Jan-03	57	26	42	23
01-Feb-03	60	33	47	18
02-Feb-03	40	24	32	33
03-Feb-03	30	13	22	43
04-Feb-03	29	7	18	47
05-Feb-03	29	8	19	46
06-Feb-03	11	-3	4	61
07-Feb-03	34	-9	13	52
08-Feb-03	29	3	16	49
09-Feb-03	30	4	17	48
10-Feb-03	27	13	20	45
11-Feb-03	33	11	22	43
12-Feb-03	39	10	25	40
13-Feb-03	38	15	27	38
14-Feb-03	29	12	21	44
15-Feb-03	28	13	21	44
16-Feb-03	49	20	35	30
17-Feb-03	48	28	38	27
18-Feb-03	45	21	33	32
19-Feb-03	52	22	37	28
20-Feb-03	49	24	37	28
21-Feb-03	43	12	28	37
22-Feb-03	13	2	8	57
23-Feb-03	3	-11	-4	69
24-Feb-03	4	-17	-7	72
25-Feb-03	28	-13	8	57
26-Feb-03	38	4	21	44
27-Feb-03	32	13	23	42

Source:
Column (B) and (C): NOAA Climatological Data South Dakota Volume107 No. 11 to Volume 108 No.12
Column (D): (Column (B) + Column (C))/2
Column (E): 65 - Column (D).

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Temperature Hi	Low	Avg	HDD 65
(A)	(B)	(C)	(D)	(E)
28-Feb-03	39	15	27	38
01-Mar-03	34	10	22	43
02-Mar-03	42	3	23	42
03-Mar-03	35	9	22	43
04-Mar-03	14	2	8	57
05-Mar-03	35	6	21	44
06-Mar-03	38	9	24	41
07-Mar-03	45	4	25	40
08-Mar-03	8	-1	4	61
09-Mar-03	16	2	9	56
10-Mar-03	50	8	29	36
11-Mar-03	56	22	39	26
12-Mar-03	56	22	39	26
13-Mar-03	74	32	53	12
14-Mar-03	80	32	56	9
15-Mar-03	65	34	50	15
16-Mar-03	71	35	53	12
17-Mar-03	52	34	43	22
18-Mar-03	35	32	34	31
19-Mar-03	40	32	36	29
20-Mar-03	50	28	39	26
21-Mar-03	55	25	40	25
22-Mar-03	65	32	49	16
23-Mar-03	73	34	54	11
24-Mar-03	53	28	41	24
25-Mar-03	53	26	40	25
26-Mar-03	56	36	46	19
27-Mar-03	40	23	32	33
28-Mar-03	37	18	28	37
29-Mar-03	44	9	27	38
30-Mar-03	64	25	45	20
31-Mar-03	77	43	60	5
01-Apr-03	81	36	59	6
02-Apr-03	46	27	37	28
03-Apr-03	51	30	41	24
04-Apr-03	40	23	32	33
05-Apr-03	52	19	36	29
06-Apr-03	36	29	33	32
07-Apr-03	43	28	36	29
08-Apr-03	64	20	42	23
09-Apr-03	77	27	52	13
10-Apr-03	67	39	53	12
11-Apr-03	73	36	55	10
12-Apr-03	86	40	63	2
13-Apr-03	87	42	65	0
14-Apr-03	75	48	62	3
15-Apr-03	67	44	56	9
16-Apr-03	56	36	46	19

Source:
Column (B) and (C): NOAA Climatological Data South Dakota Volume107 No. 11 to Volume 108 No.12
Column (D): (Column (B) + Column (C))/2
Column (E): 65 - Column (D)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

	Temperature			
Date	Hi	Low	Avg	HDD 65
(A)	(B)	(C)	(D)	(E)
17-Apr-03	66	34	50	15
18-Apr-03	48	36	42	23
19-Apr-03	53	36	45	20
20-Apr-03	64	38	51	14
21-Apr-03	67	34	51	14
22-Apr-03	71	36	54	11
23-Apr-03	55	45	50	15
24-Apr-03	51	40	46	19
25-Apr-03	55	33	44	21
26-Apr-03	79	42	61	4
27-Apr-03	62	34	48	17
28-Apr-03	51	43	47	18
29-Apr-03	47	42	45	20
30-Apr-03	44	42	43	22
01-May-03	50	38	44	21
02-May-03	64	35	50	15
03-May-03	72	42	57	8
04-May-03	60	43	52	13
05-May-03	57	34	46	19
06-May-03	58	31	45	20
07-May-03	71	34	53	12
08-May-03	54	42	48	17
09-May-03	54	41	48	17
10-May-03	50	38	44	21
11-May-03	59	36	48	17
12-May-03	67	33	50	15
13-May-03	68	43	56	9
14-May-03	68	39	54	11
15-May-03	75	40	58	7
16-May-03	74	48	61	4
17-May-03	63	50	57	8
18-May-03	64	42	53	12
19-May-03	54	33	44	21
20-May-03	61	25	43	22
21-May-03	72	37	55	10
22-May-03	69	50	60	5
23-May-03	77	46	62	3
24-May-03	75	50	63	2
25-May-03	79	44	62	3
26-May-03	79	53	66	0
27-May-03	82	57	70	0
28-May-03	82	56	69	0
29-May-03	94	55	75	0
30-May-03	78	50	64	1
31-May-03	70	46	58	7
01-Jun-03	66	42	54	11
02-Jun-03	74	44	59	6
03-Jun-03	69	45	57	8

Source:
Column (B) and (C): NOAA Climatological Data South Dakota Volume107 No. 11 to Volume 108 No.12
Column (D): (Column (B) + Column (C))/2
Column (E): 65 - Column (D).
Note: Negative values are shown as a 0 in Column (E)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Temperature Hi	Low	Avg	HDD 65
(A)	(B)	(C)	(D)	(E)
04-Jun-03	70	42	56	9
05-Jun-03	62	44	53	12
06-Jun-03	63	43	53	12
07-Jun-03	62	40	51	14
08-Jun-03	71	40	56	9
09-Jun-03	77	45	61	4
10-Jun-03	73	48	61	4
11-Jun-03	77	49	63	2
12-Jun-03	79	46	63	2
13-Jun-03	80	46	63	2
14-Jun-03	82	50	66	0
15-Jun-03	89	51	70	0
16-Jun-03	87	59	73	0
17-Jun-03	80	56	68	0
18-Jun-03	83	55	69	0
19-Jun-03	84	52	68	0
20-Jun-03	83	60	72	0
21-Jun-03	86	56	71	0
22-Jun-03	84	56	70	0
23-Jun-03	68	51	60	5
24-Jun-03	53	46	50	15
25-Jun-03	65	45	55	10
26-Jun-03	78	43	61	4
27-Jun-03	85	50	68	0
28-Jun-03	71	49	60	5
29-Jun-03	81	48	65	0
30-Jun-03	93	54	74	0
01-Jul-03	98	65	82	0
02-Jul-03	99	64	82	0
03-Jul-03	94	64	79	0
04-Jul-03	89	57	73	0
05-Jul-03	89	56	73	0
06-Jul-03	84	54	69	0
07-Jul-03	84	55	70	0
08-Jul-03	93	62	78	0
09-Jul-03	89	59	74	0
10-Jul-03	91	54	73	0
11-Jul-03	87	55	71	0
12-Jul-03	95	54	75	0
13-Jul-03	105	60	83	0
14-Jul-03	92	62	77	0
15-Jul-03	100	56	78	0
16-Jul-03	99	64	82	0
17-Jul-03	98	71	85	0
18-Jul-03	90	68	79	0
19-Jul-03	100	62	81	0
20-Jul-03	96	66	81	0
21-Jul-03	92	59	76	0

Source:
Column (B) and (C): NOAA Climatological Data South Dakota Volume107 No. 11 to Volume 108 No.12
Column (D): (Column (B) + Column (C))/2
Column (E): 65 - Column (D)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Temperature Hi	Low	Avg	HDD 65
(A)	(B)	(C)	(D)	(E)
22-Jul-03	86	56	71	0
23-Jul-03	98	55	77	0
24-Jul-03	109	65	87	0
25-Jul-03	104	69	87	0
26-Jul-03	91	68	80	0
27-Jul-03	84	58	71	0
28-Jul-03	93	56	75	0
29-Jul-03	94	61	78	0
30-Jul-03	92	54	73	0
31-Jul-03	93	59	76	0
01-Aug-03	85	55	70	0
02-Aug-03	89	54	72	0
03-Aug-03	96	58	77	0
04-Aug-03	93	65	79	0
05-Aug-03	92	63	78	0
06-Aug-03	91	55	73	0
07-Aug-03	90	64	77	0
08-Aug-03	91	65	78	0
09-Aug-03	93	62	78	0
10-Aug-03	91	61	76	0
11-Aug-03	93	58	76	0
12-Aug-03	98	64	81	0
13-Aug-03	99	64	82	0
14-Aug-03	100	67	84	0
15-Aug-03	99	64	82	0
16-Aug-03	100	60	80	0
17-Aug-03	93	60	77	0
18-Aug-03	88	63	76	0
19-Aug-03	91	59	75	0
20-Aug-03	97	60	79	0
21-Aug-03	84	56	70	0
22-Aug-03	103	60	82	0
23-Aug-03	101	69	85	0
24-Aug-03	94	67	81	0
25-Aug-03	98	60	79	0
26-Aug-03	97	60	79	0
27-Aug-03	101	67	84	0
28-Aug-03	90	57	74	0
29-Aug-03	64	49	57	8
30-Aug-03	63	52	58	7
31-Aug-03	73	52	63	2
01-Sep-03	90	51	71	0
02-Sep-03	81	57	69	0
03-Sep-03	80	48	64	1
04-Sep-03	94	50	72	0
05-Sep-03	96	59	78	0
06-Sep-03	97	55	76	0
07-Sep-03	90	61	76	0

Source:
Column (B) and (C): NOAA Climatological Data South Dakota Volume107 No. 11 to Volume 108 No.12
Column (D): (Column (B) + Column (C))/2
Column (E): 65 - Column (D).
Note: Negative values are shown as a 0 in Column (E)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Temperature			
	Hi	Low	Avg	HDD 65
(A)	(B)	(C)	(D)	(E)
08-Sep-03	89	60	75	0
09-Sep-03	79	51	65	0
10-Sep-03	66	48	57	8
11-Sep-03	73	50	62	3
12-Sep-03	74	49	62	3
13-Sep-03	65	39	52	13
14-Sep-03	69	38	54	11
15-Sep-03	83	41	62	3
16-Sep-03	88	48	68	0
17-Sep-03	63	38	51	14
18-Sep-03	59	33	46	19
19-Sep-03	73	34	54	11
20-Sep-03	77	42	60	5
21-Sep-03	66	39	53	12
22-Sep-03	64	36	50	15
23-Sep-03	85	42	64	1
24-Sep-03	63	35	49	16
25-Sep-03	81	37	59	6
26-Sep-03	63	42	53	12
27-Sep-03	66	39	53	12
28-Sep-03	61	34	48	17
29-Sep-03	55	33	44	21
30-Sep-03	61	34	48	17
01-Oct-03	63	30	47	18
02-Oct-03	74	32	53	12
03-Oct-03	72	41	57	8
04-Oct-03	75	41	58	7
05-Oct-03	81	45	63	2
06-Oct-03	81	49	65	0
07-Oct-03	89	43	66	0
08-Oct-03	78	45	62	3
09-Oct-03	92	45	69	0
10-Oct-03	68	44	56	9
11-Oct-03	61	38	50	15
12-Oct-03	73	35	54	11
13-Oct-03	61	36	49	16
14-Oct-03	55	32	44	21
15-Oct-03	56	34	45	20
16-Oct-03	51	34	43	22
17-Oct-03	85	39	62	3
18-Oct-03	83	46	65	0
19-Oct-03	83	44	64	1
20-Oct-03	76	48	62	3
21-Oct-03	83	48	66	0
22-Oct-03	82	50	66	0
23-Oct-03	71	40	56	9
24-Oct-03	56	30	43	22
25-Oct-03	42	21	32	33

Source:
Column (B) and (C): NOAA Climatological Data South Dakota Volume107 No. 11 to Volume 108 No.12
Column (D): (Column (B) + Column (C))/2
Column (E): 65 - Column (D)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

	Temperature			
Date	Hi	Low	Avg	HDD 65
(A)	(B)	(C)	(D)	(E)
26-Oct-03	63	30	47	18
27-Oct-03	72	39	56	9
28-Oct-03	52	39	46	19
29-Oct-03	45	33	39	26
30-Oct-03	35	22	29	36
31-Oct-03	25	20	23	42
01-Nov-03	37	19	28	37
02-Nov-03	31	19	25	40
03-Nov-03	26	20	23	42
04-Nov-03	24	10	17	48
05-Nov-03	21	0	11	54
06-Nov-03	33	0	17	48
07-Nov-03	26	8	17	48
08-Nov-03	24	10	17	48
09-Nov-03	37	10	24	41
10-Nov-03	50	28	39	26
11-Nov-03	54	28	41	24
12-Nov-03	42	21	32	33
13-Nov-03	53	18	36	29
14-Nov-03	51	33	42	23
15-Nov-03	54	27	41	24
16-Nov-03	58	24	41	24
17-Nov-03	57	29	43	22
18-Nov-03	55	27	41	24
19-Nov-03	68	37	53	12
20-Nov-03	64	26	45	20
21-Nov-03	26	18	22	43
22-Nov-03	18	7	13	52
23-Nov-03	12	-3	5	60
24-Nov-03	36	8	22	43
25-Nov-03	31	9	20	45
26-Nov-03	41	8	25	40
27-Nov-03	34	14	24	41
28-Nov-03	37	9	23	42
29-Nov-03	54	29	42	23
30-Nov-03	43	25	34	31
01-Dec-03	41	26	34	31
02-Dec-03	40	25	33	32
03-Dec-03	45	25	35	30
04-Dec-03	40	22	31	34
05-Dec-03	33	12	23	42
06-Dec-03	56	28	42	23
07-Dec-03	53	32	43	22
08-Dec-03	32	28	30	35
09-Dec-03	35	16	26	39
10-Dec-03	26	14	20	45
11-Dec-03	18	-1	9	56
12-Dec-03	26	-2	12	53

Source:
Column (B) and (C): NOAA Climatological Data South Dakota Volume107 No. 11 to Volume 108 No.12
Column (D): (Column (B) + Column (C))/2
Column (E): 65 - Column (D).
Note: Negative values are shown as a 0 in Column (E)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

	Temperature			
Date	Hi	Low	Avg	HDD 65
(A)	(B)	(C)	(D)	(E)
13-Dec-03	46	8	27	38
14-Dec-03	46	21	34	31
15-Dec-03	36	21	29	36
16-Dec-03	43	19	31	34
17-Dec-03	49	26	38	27
18-Dec-03	44	22	33	32
19-Dec-03	49	19	34	31
20-Dec-03	61	26	44	21
21-Dec-03	48	33	41	24
22-Dec-03	43	23	33	32
23-Dec-03	47	23	35	30
24-Dec-03	46	19	33	32
25-Dec-03	48	31	40	25
26-Dec-03	41	25	33	32
27-Dec-03	37	25	31	34
28-Dec-03	32	15	24	41
29-Dec-03	32	11	22	43
30-Dec-03	30	15	23	42
31-Dec-03	49	9	29	36

Source:
Column (B) and (C): NOAA Climatological Data South Dakota Volume107 No. 11 to Volume 108 No.12
Column (D): (Column (B) + Column (C))/2
Column (E): 65 - Column (D).
Note: Negative values are shown as a 0 in Column (E)

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
24-Nov-02	30	35
25-Nov-02	29	35
26-Nov-02	29	35
27-Nov-02	29	36
28-Nov-02	29	36
29-Nov-02	28	36
30-Nov-02	28	37
01-Dec-02	28	37
02-Dec-02	28	37
03-Dec-02	27	37
04-Dec-02	27	37
05-Dec-02	27	37
06-Dec-02	27	38
07-Dec-02	26	38
08-Dec-02	26	38
09-Dec-02	26	38
10-Dec-02	26	39
11-Dec-02	25	39
12-Dec-02	25	39
13-Dec-02	25	39
14-Dec-02	25	40
15-Dec-02	25	40
16-Dec-02	24	40
17-Dec-02	24	40
18-Dec-02	24	40
19-Dec-02	24	41
20-Dec-02	24	41
21-Dec-02	24	41
22-Dec-02	24	41
23-Dec-02	23	41
24-Dec-02	23	41
25-Dec-02	23	41
26-Dec-02	23	42
27-Dec-02	23	42
28-Dec-02	23	42
29-Dec-02	23	42
30-Dec-02	22	42
31-Dec-02	22	43
01-Jan-03	22	43
02-Jan-03	22	43
03-Jan-03	22	43
04-Jan-03	22	43
05-Jan-03	22	43

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
06-Jan-03	22	43
07-Jan-03	22	43
08-Jan-03	22	43
09-Jan-03	22	43
10-Jan-03	22	43
11-Jan-03	22	43
12-Jan-03	22	43
13-Jan-03	22	43
14-Jan-03	22	43
15-Jan-03	22	43
16-Jan-03	22	43
17-Jan-03	22	43
18-Jan-03	22	42
19-Jan-03	22	42
20-Jan-03	22	42
21-Jan-03	22	42
22-Jan-03	22	42
23-Jan-03	23	42
24-Jan-03	23	42
25-Jan-03	23	42
26-Jan-03	23	42
27-Jan-03	23	41
28-Jan-03	24	41
29-Jan-03	24	41
30-Jan-03	24	41
31-Jan-03	24	41
01-Feb-03	24	41
02-Feb-03	24	41
03-Feb-03	25	40
04-Feb-03	25	40
05-Feb-03	25	40
06-Feb-03	25	40
07-Feb-03	26	40
08-Feb-03	26	39
09-Feb-03	26	39
10-Feb-03	26	39
11-Feb-03	26	39
12-Feb-03	27	39
13-Feb-03	27	38
14-Feb-03	27	38
15-Feb-03	27	38
16-Feb-03	28	38
17-Feb-03	28	37

Source:
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm

Rapid City DD 0103to1203
Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
18-Feb-03	28	37
19-Feb-03	28	37
20-Feb-03	29	37
21-Feb-03	29	36
22-Feb-03	29	36
23-Feb-03	29	36
24-Feb-03	30	36
25-Feb-03	30	35
26-Feb-03	30	35
27-Feb-03	30	35
28-Feb-03	30	35
01-Mar-03	30	35
02-Mar-03	30	34
03-Mar-03	31	34
04-Mar-03	31	34
05-Mar-03	32	33
06-Mar-03	32	33
07-Mar-03	32	32
08-Mar-03	33	32
09-Mar-03	33	32
10-Mar-03	33	32
11-Mar-03	33	31
12-Mar-03	34	31
13-Mar-03	34	31
14-Mar-03	34	30
15-Mar-03	35	30
16-Mar-03	35	30
17-Mar-03	35	29
18-Mar-03	36	29
19-Mar-03	36	29
20-Mar-03	36	29
21-Mar-03	36	28
22-Mar-03	37	28
23-Mar-03	37	28
24-Mar-03	37	27
25-Mar-03	38	27
26-Mar-03	38	27
27-Mar-03	38	27
28-Mar-03	39	26
29-Mar-03	39	26
30-Mar-03	39	26
31-Mar-03	40	25
01-Apr-03	40	25

Source:

Rapid City DD 0102to1203

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
02-Apr-03	40	24
03-Apr-03	41	24
04-Apr-03	41	24
05-Apr-03	41	23
06-Apr-03	42	23
07-Apr-03	42	23
08-Apr-03	42	22
09-Apr-03	42	22
10-Apr-03	43	22
11-Apr-03	43	21
12-Apr-03	43	21
13-Apr-03	44	21
14-Apr-03	44	20
15-Apr-03	45	20
16-Apr-03	45	20
17-Apr-03	45	19
18-Apr-03	46	19
19-Apr-03	46	19
20-Apr-03	46	18
21-Apr-03	47	18
22-Apr-03	47	18
23-Apr-03	47	17
24-Apr-03	48	17
25-Apr-03	48	17
26-Apr-03	48	16
27-Apr-03	49	16
28-Apr-03	49	16
29-Apr-03	49	15
30-Apr-03	50	15
01-May-03	50	15
02-May-03	50	15
03-May-03	50	15
04-May-03	51	14
05-May-03	51	14
06-May-03	51	14
07-May-03	52	13
08-May-03	52	13
09-May-03	52	13
10-May-03	53	12
11-May-03	53	12
12-May-03	54	11
13-May-03	54	11
14-May-03	54	11

Source:
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm

Rapid City DD 0103to1203
Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
15-May-03	55	10
16-May-03	55	10
17-May-03	55	10
18-May-03	56	9
19-May-03	57	8
20-May-03	57	8
21-May-03	57	8
22-May-03	57	8
23-May-03	58	7
24-May-03	58	7
25-May-03	58	7
26-May-03	59	7
27-May-03	59	7
28-May-03	59	6
29-May-03	59	6
30-May-03	60	6
31-May-03	60	6
01-Jun-03	60	6
02-Jun-03	60	6
03-Jun-03	60	6
04-Jun-03	61	5
05-Jun-03	61	5
06-Jun-03	61	5
07-Jun-03	62	4
08-Jun-03	63	4
09-Jun-03	63	4
10-Jun-03	63	4
11-Jun-03	63	3
12-Jun-03	64	3
13-Jun-03	64	3
14-Jun-03	64	2
15-Jun-03	65	2
16-Jun-03	65	2
17-Jun-03	65	2
18-Jun-03	65	2
19-Jun-03	66	2
20-Jun-03	66	2
21-Jun-03	67	2
22-Jun-03	67	2
23-Jun-03	67	2
24-Jun-03	67	2
25-Jun-03	67	2
26-Jun-03	67	2

Source:

Rapid City DD 2100' 1993

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
27-Jun-03	68	1
28-Jun-03	69	1
29-Jun-03	69	1
30-Jun-03	69	1
01-Jul-03	69	1
02-Jul-03	69	1
03-Jul-03	70	1
04-Jul-03	70	1
05-Jul-03	70	1
06-Jul-03	70	1
07-Jul-03	70	1
08-Jul-03	71	1
09-Jul-03	71	1
10-Jul-03	71	1
11-Jul-03	71	1
12-Jul-03	71	1
13-Jul-03	72	1
14-Jul-03	72	1
15-Jul-03	72	1
16-Jul-03	72	1
17-Jul-03	72	0
18-Jul-03	72	0
19-Jul-03	72	0
20-Jul-03	73	0
21-Jul-03	73	0
22-Jul-03	73	0
23-Jul-03	73	0
24-Jul-03	73	0
25-Jul-03	73	0
26-Jul-03	73	0
27-Jul-03	73	0
28-Jul-03	73	0
29-Jul-03	73	0
30-Jul-03	73	0
31-Jul-03	73	0
01-Aug-03	73	0
02-Aug-03	73	0
03-Aug-03	73	0
04-Aug-03	73	0
05-Aug-03	73	0
06-Aug-03	73	0
07-Aug-03	73	0
08-Aug-03	73	0

Source:
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm

Rapid City DD 0103to1203
Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
09-Aug-03	73	0
10-Aug-03	73	0
11-Aug-03	73	0
12-Aug-03	72	0
13-Aug-03	72	0
14-Aug-03	72	0
15-Aug-03	72	0
16-Aug-03	72	0
17-Aug-03	71	1
18-Aug-03	71	1
19-Aug-03	71	1
20-Aug-03	71	1
21-Aug-03	70	1
22-Aug-03	70	1
23-Aug-03	70	1
24-Aug-03	70	1
25-Aug-03	69	1
26-Aug-03	69	2
27-Aug-03	69	2
28-Aug-03	68	2
29-Aug-03	68	2
30-Aug-03	67	2
31-Aug-03	67	2
01-Sep-03	66	3
02-Sep-03	66	3
03-Sep-03	66	3
04-Sep-03	65	3
05-Sep-03	65	3
06-Sep-03	64	4
07-Sep-03	64	4
08-Sep-03	64	4
09-Sep-03	63	5
10-Sep-03	63	5
11-Sep-03	62	5
12-Sep-03	62	5
13-Sep-03	62	5
14-Sep-03	61	6
15-Sep-03	61	6
16-Sep-03	60	6
17-Sep-03	60	7
18-Sep-03	60	7
19-Sep-03	59	7
20-Sep-03	59	7

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
21-Sep-03	58	8
22-Sep-03	58	8
23-Sep-03	58	8
24-Sep-03	57	9
25-Sep-03	57	9
26-Sep-03	56	10
27-Sep-03	56	10
28-Sep-03	56	10
29-Sep-03	55	10
30-Sep-03	55	10
01-Oct-03	55	10
02-Oct-03	54	11
03-Oct-03	54	11
04-Oct-03	54	11
05-Oct-03	53	12
06-Oct-03	53	12
07-Oct-03	52	13
08-Oct-03	52	13
09-Oct-03	52	13
10-Oct-03	51	14
11-Oct-03	51	14
12-Oct-03	50	15
13-Oct-03	50	15
14-Oct-03	49	16
15-Oct-03	49	16
16-Oct-03	48	17
17-Oct-03	48	17
18-Oct-03	47	18
19-Oct-03	47	18
20-Oct-03	47	18
21-Oct-03	46	19
22-Oct-03	46	19
23-Oct-03	45	20
24-Oct-03	45	20
25-Oct-03	44	21
26-Oct-03	43	22
27-Oct-03	43	22
28-Oct-03	42	23
29-Oct-03	42	23
30-Oct-03	41	24
31-Oct-03	41	24
01-Nov-03	40	25
02-Nov-03	40	25

Source:
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm

Rapid City DD 0103to1203
Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
03-Nov-03	39	26
04-Nov-03	38	26
05-Nov-03	38	27
06-Nov-03	37	27
07-Nov-03	37	28
08-Nov-03	36	28
09-Nov-03	36	29
10-Nov-03	35	29
11-Nov-03	35	29
12-Nov-03	35	30
13-Nov-03	34	30
14-Nov-03	34	31
15-Nov-03	33	31
16-Nov-03	33	32
17-Nov-03	32	32
18-Nov-03	32	32
19-Nov-03	32	33
20-Nov-03	31	33
21-Nov-03	31	33
22-Nov-03	31	34
23-Nov-03	30	34
24-Nov-03	30	35
25-Nov-03	29	35
26-Nov-03	29	35
27-Nov-03	29	36
28-Nov-03	29	36
29-Nov-03	28	36
30-Nov-03	28	37
01-Dec-03	28	37
02-Dec-03	28	37
03-Dec-03	27	37
04-Dec-03	27	37
05-Dec-03	27	37
06-Dec-03	27	38
07-Dec-03	26	38
08-Dec-03	26	38
09-Dec-03	26	38
10-Dec-03	26	39
11-Dec-03	25	39
12-Dec-03	25	39
13-Dec-03	25	39
14-Dec-03	25	40
15-Dec-03	25	40

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
November 24, 2002 to December 31, 2003

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
16-Dec-03	24	40
17-Dec-03	24	40
18-Dec-03	24	40
19-Dec-03	24	41
20-Dec-03	24	41
21-Dec-03	24	41
22-Dec-03	24	41
23-Dec-03	23	41
24-Dec-03	23	41
25-Dec-03	23	41
26-Dec-03	23	42
27-Dec-03	23	42
28-Dec-03	23	42
29-Dec-03	23	42
30-Dec-03	22	42
31-Dec-03	22	43

Source:
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm

Rapid City DD 0103to1203
Daily Normals

RECEIVED
OCT 19 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA- DAKOTA UTILITIES
DOCKET NO. NG04-004

TESTIMONY & EXHIBITS OF DAVID A. JACOBSON
ON BEHALF OF THE COMMISSION STAFF
October 2004

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES
DOCKET NO. NG04-004

TESTIMONY & EXHIBITS OF DAVID A. JACOBSON
ON BEHALF OF THE COMMISSION STAFF
October 2004

Q. What is your name and by whom are you employed?

A. My name is David A. Jacobson and I am presently employed as a Utility Analyst with the Commission Staff of the Public Utilities Commission (Commission). My business address is Public Utilities Commission, State Capitol Building, Pierre, South Dakota 57501.

Q. Please describe your educational background and experience.

A. I received a Bachelor of Science Degree in Business Administration majoring in business management from the University of South Dakota in 1980. I subsequently returned to the University in 1982 and completed major course work in accounting. I have been with the Commission since May of 1984. I have previously presented testimony in 15 general rate case applications and also in numerous other docketed matters before the Commission.

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

A. I shall present Staff's determination of working capital for Montana-Dakota Utilities Co. (MDU or Company), and address Company proposed adjustments regarding Labor and associated payroll taxes, benefits expense, insurance expense, contract labor and consulting expense and the Company's Supplemental Income Security Plan (SISP). In addition I shall address certain tariff changes proposed by the Company.

Q. Did MDU provide an analysis of its working capital requirements?

A. The Company provided 13-month beginning/ending period average balances for material and supplies, prepaid insurance, the unamortized FAS 106 balance and customer advances for construction. The Company did not perform a lead-lag study which would result in a determination of cash working capital requirements.

Q. How were you able to perform a calculation to determine MDU's working capital allowance?

A. I first adjusted materials and supplies, prepaid insurance, the unamortized FAS 106 balance and customer advances for construction by re-computing test year averages using 13 point end of month averages. I then updated these balances to more recently available 13 point averages. This adjustment is shown on Exhibit__(DAJ-1), Schedule 3.

To determine MDU's cash working capital allowance, I used the best available information to construct a lead lag calculation.

Q. Please describe how a lead-lag calculation measures working capital requirements.

A. A lead-lag analysis measures (1) the time between when service is provided to the utility and when those costs are paid by the utility, and (2) the time between when a service is provided to a customer and when revenues for that service are received by the utility. These differences, expressed in days, are multiplied by the average daily operating expense which results in the working capital required or available.

Q. How did you determine the various expense lead days included in your analysis?

A. Because MDU's last rate case, Docket NG02-011, was filed less than 18 months prior to the filing of this case, and because no additional Information regarding a cash working capital determination was provided in this case, I utilized the same information used in Docket NG02-011 with the exception of the days associated with South Dakota Gross Receipts Tax. Since that filing, the due date for payment of such taxes has changed from June 1 of each year to July 15. The

detail of the sources for expense lead days and the cash working capital calculation can be found on Exhibit __(DAJ-1), Schedule 1.

Q. How did you compute MDU's revenue lag?

A. I used a 20-day bill payment lag. South Dakota Administrative Rules provide that a bill becomes delinquent after 20 days and thereafter a company can assess a late payment charge. In collecting this charge, the company is compensated for the costs of extending credit to their customers when payments are made later than 20 days from billing. When adopting this approach, it is appropriate to remove late payment fees from test year revenues for ratemaking purposes. In this case, MDU has proposed an adjustment including late payment charges in test year revenues but because of Staff's use of a 20 day bill payment lag, MDU's inclusion of these revenues is not appropriate and they have been removed from Staff's determination of MDU's test year revenues. For processing days, the time between when meters are read and when a bill is rendered, I utilized one day. Although no definitive information was available, it has been my observation that processing days for companies have decreased in the last several years due to the application of new technologies. Processing days for the other two local distribution companies regulated by the Commission have most recently been determined to be approximately one day. Lacking an actual current study of this measure, I believe one day is appropriate in this case.

Q. Are there other sources of working capital available to the Company?

A. Yes. Taxes collected by the Company and held until payment are depicted in Exhibit__(DAJ-1), Schedule 2.

Q. Has MDU proposed an adjustment to test year insurance expense?

A. The Company proposed an adjustment increasing insurance expense based on projections. It has long been the policy of the South Dakota Commission, and appropriately so because of their speculative nature, to avoid the use of projections for ratemaking purposes. Updated actual insurance expense information was requested by Staff and after review, I have proposed a minor

adjustment incorporating that information. This adjustment is shown on Exhibit__(DAJ-2), Schedule 1.

Q. Have you reviewed the adjustment proposed by MDU for increasing labor expense over test year amounts?

A. In MDU's last rate case, NG02-011, the Company supplied a new union Contract for Gas Distribution and Service employees. The contract specifies annual hourly wage increases which become effective May 1st of each year 2002 through 2006. Because MDU was unable to provide South Dakota labor expense separated by union as opposed to non-union, I performed an allocation using the number of South Dakota union employees compared to total South Dakota employees to determine a South Dakota union labor expense amount. I then applied the May 1, 2003, union labor increase per the union contract to January, 2003, through April, 2003, union labor straight time, premium time and vacation time to annualize the May 1 increase. These categories reflect labor costs associated with hourly compensation as shown in the contract. I then further adjusted these categories of MDU's union labor expense for the increase which took effect May 1, 2004, as this increase in wages has taken place and is known and measurable and took place within a reasonable time after the test year. For the bonuses and commissions category of expense, the Company proposed using a three year average instead of actual test year results. Given the randomly variable nature of this category of expense, Staff considers this adjustment appropriate. Because South Dakota Gas expenses were not available for prior years, Staff proportionally applied MDU's adjustment regarding the three year average bonus and commission expense to test year South Dakota Gas expense.

Regarding the Company's non-union labor expense, Data Responses by MDU indicate that the Company adjustment to increase labor expense from test year levels is based on projections derived from their budgeting and planning process. As indicated in MDU's response and responses from Docket NG02-011, the process involves many levels of hierarchy within both the utility and parent organization. Inputs in future salary determinations include department manager

budgets, the Financial Reporting and Planning Department, the Senior Management Policy Committee, Vice President review, MDU's CEO, Senior Management of MDU Resources Group and the Board of Directors. Other inputs along the way include EEI/AGA studies, regional salary studies and other studies. Given the wide range of review by many groups and individuals and the possibility of contrasting goals, and given the possibility of goal modification over time as economic conditions change, forecasting what future salary decisions will be with certainty is fraught with uncertainty.

As a result of the above problems, Staff, as the Commission has in the past, have relied on the known and measurable increases documented by the Company to adjust labor expense. No such documented evidence has been provided by MDU in this case for non-union expenses and therefore Staff has not adjusted non-union test year labor expense. The results of Staff's labor adjustment can be seen on Exhibit__(DAJ-2), Schedule 2. The resulting change to payroll taxes can also be found on that exhibit.

Q. Did MDU propose an adjustment to employee benefits expense?

A. Once again MDU provided a forecasted benefit increase. Through data requests, I received updated actual benefits expense amounts for the 12 months ended 7/31/04 and have adjusted test year expenses by this known change, excluding the SISP, which will be discussed forthwith. Because certain of these costs have shown trends to substantially increase in recent years, independent of employee levels, it is my opinion that it is acceptable to acknowledge these updated costs MDU has experienced. The detail for this adjustment can be found on Exhibit__(DAJ-2), Schedule 3.

Q. What is your recommendation concerning the Company's proposed adjustment to contract labor and consulting expense?

A. The Company has proposed an adjustment based on the same budgeting and planning process used to support non-union labor expense. For this reason I have rejected MDU's proposed adjustment.

Q. Why is it not appropriate to update this expense as has been proposed by Staff for union labor expense?

A. A problem with matching test year operating results with test year expenses arises if one makes such an adjustment. Test year labor expenses can be adjusted for a known increase in the labor rate for individual employees because the adjustment does not reflect added employee numbers or added hours worked by employees. When numbers of employees or hours worked are adjusted from test year, it could well indicate the addition of customers and therefore revenues, which are not reflected in the test year. Without making a corresponding change to Company revenues, only the added costs are reflected thus distorting the Company's revenue requirement. Staff witness Senger discusses this matching principle further in his testimony. In the case of MDU's adjustment for contract and consulting services, there is no evidence that the proposed increase is due to higher rates paid for the same level of service as provided in the test year.

Q. Have you reviewed MDU's proposal to include the costs of the Supplemental Income Security Plan (SISP) in the regulated cost of service?

A. Yes. MDU has proposed to include $118,361 of test year SISP costs in its South Dakota Black Hills Gas cost of service and has proposed a pro forma increase of $80,485 reflecting projected 2004 expense. Briefly, as described in my testimony in Docket NG02-011, the plan provides retirement benefits in addition to Social Security, the Defined Benefit Pension Plan and MDU's 401(k) plan so that income after retirement comes closer to equaling that made prior to retirement. According to documents filed in that case, eligibility guidelines for the plan are that an individual should have a base salary of at least $80,000 and be an officer or in a position of significant influence and impact. The 2002 Proxy Statement of MDU Resources Group, Inc. states there are 76 participants in the program. Responses to Staff data requests in Docket NG02-011 explained that 26 of these 76 senior management personnel participating in the SISP are with MDU. However data responses received by Staff in this proceeding indicate that there

were 87 total participants in SISP with 61 attributable to MDU as of December 31, 2003.

Q. Do you have an opinion on whether this expense should be included for recovery in rates from ratepayers?

A. I believe the same arguments supporting the disallowance of recovery of SISP as put forth in Docket NG02-011 are still valid. The other pension and retirement plans utilized by MDU are fully included in the cost of service. Key personnel employed by MDU are compensated with bonuses, the Key Employee Stock Option Plan, the Executive Long Term Incentive Plan and other plans. These plans rely on stockholder enrichment as a key measure in determining rewards, largely to upper level management. It is apparent that stockholder welfare is a major concern of senior management and, because Staff has allowed these programs to be funded, it seems only reasonable to have the Stockholders of MDU Resources Group continue to fund the SISP as they have in the past.

Again, another point to consider is that the SISP is available *only* to upper management. It can well be argued that employees with smaller incomes at retirement are more in need of having a greater portion of their salaries replaced than retirees with larger ending salaries. While MDU has acknowledged this matter, this plan does not contribute to that end. Also, employees with larger salaries may also have the ability to save more for retirement in plans outside of Company sponsored plans than those who spend a larger share of their income on meeting daily costs of living. Because of these issues, I would not allow SISP costs to be recovered from South Dakota ratepayers.

Q. Have you reviewed the miscellaneous changes MDU has proposed to their tariff in this case and do you have any comments?

A. Yes. Other than the monetary rate changes proposed in the revised tariffs and certain labeling errors, the revisions seek to clarify and correct the currently effective tariffs. I would have no objection to these revisions.

Q. I have no further questions.

Montana-Dakota Utilities Co.
South Dakota - Gas
Cash Working Capital
Test Year Ended 12/31/03

Exhibit__(DAJ-1)
Schedule 1
Page 1

Line	Description	South Dakota Per Books	Adjustments	Pro Forma Expense	Expense Per Day	Expense Lead Days	Expense Dollar Days
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Operation & Maintenance						
1	Gas Purchases	$ 34,335,947	$ -	$ 34,335,947	$ 94,071	41.2	$ 3,875,725
2	Labor Expense	4,033,579	168,257	4,201,836	11,512	19	218,728
3	Fringe Benefit	690,769	87,541	778,310	2,132	27.7	59,056
4	Insurance Expense	255,242	(3,643)	251,599	N/A		
5	Uncollectible Accounts Exp.	139,674	-	139,674	383	230.6	88,320
6	Regulatory Commission Exp.	1,869	-	1,869	N/A		
7	Other O & M Expense	2,143,676	207,420	2,351,096	6,441	16.4	105,632
8	Total O & M	41,600,756	459,575	42,060,331	114,539		4,241,829
9	Depreciation & Amortization	1,815,584	(376,103)	1,439,481	3,944	0	-
10	Deferred Income Taxes	997,246	(23,416)	973,830	2,668	0	-
11	Ad Valorem Tax	388,906	-	388,906	1,065	395.25	420,941
12	Payroll - FICA	272,985	15,177	288,162	789	19	14,991
13	Payroll - FUTA	3,880	219	4,099	11	47	517
14	Payroll - SUTA	10,598	269	10,867	30	47	1,410
15	S D Gross Receipts Tax	46,953	22,110	69,063	189	379.3	71,688
16	Federal Income Tax	(1,118,415)	498,593	(619,822)	(1,698)	37	(62,826)
17	Interest on Long Term Debt	811,985	(135,813)	676,172	1,853	91.3	169,179
18	Preferred Stock Dividends			36,601	100	45.6	4,560
19	Total	$ 44,830,478	$ 460,611	$ 45,327,689	$ 123,490	39.37	$ 4,862,289.00

20	Revenue Lag Days	36.21
21	Expense Lead Days	39.37
22	Net Days	(3.16)
23	Expense per Day	123,490
24	Cash Working Capital	(390,228)

Sources :

Column (b)
Line 1: Statement H, page 2 of 3 and Schedule H-1, page 3 of 21
Line 2: Statement H, Schedule H-1, page 4 of 21
Line 3: Statement H, Schedule H-1, page 5 of 21
Line 4: Statement H, Schedule H-1, page 6 of 21
Line 5: Statement H, Schedule H-1, page 13 of 21
Line 6: Statement H, Schedule H-1, page 17 of 21
Line 7:
Sum of: Statement H, Schedule H-1, Page 20 of 21, Contract Labor - $691,086, vehicles and Work Equipment - $281,031, postage - $160,126, telephone - $103,085, page 21 of 21 office supplies - $103,452, Company Consumption - $37,435, Computer Rental - $40,453, Industry Dues - $42,948, Advertising - $44,223 and *All Other O&M - $639,837*
Line 9: Statement J, page 1 of 8
Line 10: Statement K, page 12 of 16
Line 11: Statement L, page 1 of 1
Line12: Statement L, page 1 of 1
Line 13: DR1-4, support for Statement L, page 1
Line 14: DR1-4, support for Statement L, page 1
Line 15: Statement L, page 1 of 1
line 16: Statement K, page 5 of 16
Line 17: Statement K, page 7 of 16
line 20:Staff working papers reflects 1 day processing & 20 day cutoff
line 21: Column (g), line 19 divided by Column (e), line 19
line 22: Column (b), line 20 minus Column (b), line 21
line 23: Column (e), line 19
line 24: Column (b), line 22 multiplied by Column (b), line 23

Column (c)
line 1: KAS-1, Schedule 2, column c, line 8
line 2: KAS-1, Schedule 2, column c, line 9
line 3: KAS-1, Schedule 2, column c, line 10
line 4: KAS-1, Schedule 2, column c, line 11
line 5: KAS-1, Schedule 2, column c, line 12
line 6: KAS-1, Schedule 2, column c, line 13
line 7: KAS-1, Schedule 2, column c, line 14

Column (c) (con't)
line 9: KAS-1, Schedule 2, column c, line 16
line 10: KAS-1, Schedule 2, column c, line 26
line 11: KAS-1, Schedule 2, column c, line 28
line 12: KAS-1, Schedule 2, column c, line 21
line 13: KAS-1, Schedule 2, column c, line 22
line 14: KAS-1, Schedule 2, column c, line 23
line 15: KAS-1, Schedule 2, column c, line 24
line 16: KAS-1, Schedule 2, column c, line 25
line 17: Column d, line 17 less column b, line 17

Column (d)
line 17: KAS-1, Schedule 4, Column b, line 5
*line 18: KAS-1, Sch 1, col b, line 1 * BLC-1, Sch 1, col e, line 2*

Column (e)
line 4: Separately included in rate base
line 6: Separately included in rate base

Column (f)
lines 1, 3, 5 and 7: Docket NG94-012, Data Response 1-6
line 2: Bi-weekly payroll and 9 day lag
line 11: Staff workpaper
line 12: Bi-weekly payroll and 9 day lag
lines 13 and 14: Staff workpaper, quarterly payment
line 15: Reflects July 15 payment date
line 16: Staff workpaper
lines 17 and 18: NG94-012 Data Response 1-6
line 19: Column (g), line 19 divided by Column (e) line 19

Montana-Dakota Utilities Co.
South Dakota - Gas
Tax Collections Available
Test Year Ended 12-31-03

Exhibit__(DAJ-1)
Schedule 2
Page 1

Line	Item	South Dakota Per Books	Adjustments	Pro Forma Collections	Collections Per Day	Collection Lead Days	Available
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Employee FICA	$ 272,985	$ 15,177	$ 288,162.00	$ 789.48	19	$ 15,000.21
2	Federal Witholding	457,333	19,077	476,410.00	$ 1,305.23	19	$ 24,799.42
3	South Dakota Sales Tax	2,107,513	50,461.00	2,157,974.00	$ 5,912.26	9.4	$ 55,575.22
4	Total						$ 95,374.86

Sources:

Column (b)
line 1: Statement L, page 1 of 1
line 2: Data Response 2-2 allocated to Black Hills gas by customer count
line 3: Data Response 2-3

Column (c)
line 1: KAS-1, Schedule 2, column c, line 21
line 2: [(Col (b) line 2/KAS-1, Schedule 2, column b, line 9) * KAS-1, Schedule 2, column c, line 9]
line 3: KAS-1, Schedule 2, column c, line 5 + KAS-1, Schedule 2, column e, line 5

Column (f)
lines 1 and 2: Bi-weekly payroll and 9 day lag
line 3: [(365/12)/2]+30.4 - 36.21 (revenue lag) reflects SD sales tax remittance statute.

Montana-Dakota Utilities Co.
South Dakota - Gas
Working Capital and Customer Advances Rate Base Updates
Test Year Ended 12-31-03

Exhibit__(DAJ-1)
Schedule 3
Page 1

	(a) Item	(b) Per Books	(c) Updated	(d) Increase / (Decrease)
1	Materials and Supplies	$271,563	$264,488	($7,075)
2	Prepaid Insurance	76,422	102,287	$25,865
3	Unamortized FAS 106	150,700	141,446	($9,254)
4	Customer Advances for Costruction	57,168	53,104	($4,064)

Sources:
Column (b)
line 1: Statement F, Schedule F-1, page 2 of 5, 13 point average of per books end of month balances
line 2: Statement F, Schedule F-1, page 3 of 5, 13 point average of per books end of month balances
line 3: Statement F, Schedule F-1, page 4 of 5, 13 point average of per books end of month balances
line 4: Statement F, Schedule F-1, page 5 of 5, 13 point average of per books end of month balances

Column (c)
lines 1, 2, 3 and 4: Data Request 2-1, 13 point average of end of month balances ending 07/04

Montana-Dakota Utilities Co.
South Dakota - Gas
Insurance Expense
Test Year Ending 12-31-03

Exhibit__(DAJ-2)
Schedule 1
Page 1

1	Test Year Insurance Expense	$255,242
2	Actual Insurance Expense Year Ended 7-31-04	251,599
3	Decrease in Insurance Expense	($3,643)

Sources:
line 1: Statement H, Schedule H-1, page 6 of 21
line 2: Data Request 2-9

Montana-Dakota Utilities Co.
South Dakota - Gas
Labor and Payroll Tax Expense
Test Year Ended 12-31-03

Exhibit__(DAJ-2)
Schedule 2
Page 1

	(a) Item	(b) Amount	
1	South Dakota Test Year Labor	$4,033,579	
2	South Dakota Union Employees / Total South Dakota Employees	0.6053	
3	South Dakota Test Year Union Labor Expense	2,441,525	
	SD 1/03 - 4/03 Union Labor Expense Increased To Annualize Union Contract Increase Effective 5/1/03		
4	Straight Time	653,144	
5	Premium Time	29,287	
6	Vacation	81,804	
7	Total	$764,235	
8	SD 1/03 - 4/03 Union Labor Increased 6.72%	815,592	
9	Increase To South Dakota Union Labor Expense Annualizing 5/01/03 Increase		$51,357
10	Annualized Test Year Union Labor Subject to Union Contract Increase	2,273,390	
11	Annualized Test Year Union Labor Increased 6.31% Per Union Contract Increase Effective 05/01/04	2,416,840	
12	Increase To South Dakota Union Labor Expense Per 05/31/04 Contract Increase		$143,450
13	Test Year South Dakota Bonuses & Commissions	350,178	
14	Test Year SD Bonuses & Commissions Adjusted To Reflect Three Year Average	323,627	
15	Decrease in Test Year Bonuses & Commissions Due To Refecting Three Year Average		($26,551)
16	Total Labor Adjustment		**$168,257**
	Payroll Tax Increase		
17	FICA @ 9.02%		$15,177
18	FUTA @ .13%		$219
19	SUTA @ .16%		$269

Sources:
Column (b)
line 1: Statement H, Schedule H-1, page 4 of 21
line 2: Data Response 2-4
line 3: Line 1, *multiplied by line 2*
lines 4, 5, 6 and 7: 10/14/04 email from Rita Mulkern providing monthly South Dakota Gas labor amounts categorixed by resource code and multiplied by line 2
line 8: 05/01/03 Union Contract effective 05/01/03 - 04/30/07 *submitted in NG02-011*
line 9: Line 8 *minus line 7*
line 10: Line 8 plus (5/03 - 12/03 straight time, premium time and vacation time from 10/14/04 Rita Mulkern email multiplied by line 2)
line 11: Line 10 multiplied 6.31% per Union Contract *submitted in NG02-011*
line 12: Line 11 *minus line 10*
line 13: Rita Mulkern 10/14/04 email
line 14: Test Year Gas Utility bonuses & commissions divided by three year average Gas Utility bonuses and commissions per Workpaper Statement H, page 7 *mulitplied by line 13*
line 15: Line 13 *minus line 14*
line 16: Line 9 plus line 12 plus line 15
lines 17, 18 and 19: Applicable tax rates

Montana-Dakota Utilities Co.
South Dakota Gas
Benefits Expense
Test Year Ended 12-31-03

Exhibit__(DAJ-2)
Schedule 3
Page 1

	(a) Item	(b) Test Year Per Books Benefits Expense	(c) Benefits Expense Update Year Ended 7-31-04	(d) Increase/(Decrease)
1	Medical/Dental	$348,281	$337,771	($10,510)
2	Pension	(95,458)	33,951	129,409
3	Post Retirement	288,819	256,732	(32,087)
4	401-K	103,310	98,538	(4,772)
5	Workers Compensation	45,817	51,318	5,501
6	SISP	0	0	0
7	Total	$690,769	$778,310	$87,541

Sources:
Column (b)
lines 1-6: Statement H, Schedule H-1, page 5 of 21

Column (c)
lines 1-6: Data Response 2-6

RECEIVED
OCT 19 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG04-004

TESTIMONY & EXHIBITS OF KEITH A. SENGER
ON BEHALF OF THE COMMISSION STAFF
OCTOBER 2004

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG04-004

TESTIMONY & EXHIBITS OF KEITH A. SENGER
ON BEHALF OF THE COMMISSION STAFF
OCTOBER 2004

Q. Please state your name and business address for the record.

A. Keith Senger, Public Utilities Commission, State Capitol Building, 500 East Capitol Ave., Pierre, South Dakota, 57501.

Q. By whom are you employed and in what position?

A. I am a utility analyst for the South Dakota Public Utilities Commission (Commission).

Q. Please describe your education and work experience.

A. I graduated from Northern State University in May of 1992, with a Bachelor's Degree in Business Administration with an emphasis in Accounting and minors in both Economics and Computer Management Information Systems.

In June of 1992, I started my employment with the State of South Dakota as an auditor for the Department of Legislative Audit. In January of 1998, I accepted employment as the Audit and Compliance Manager for the South Dakota Department of Transportation. In January of 1999, I joined the Commission as a staff utility analyst.

Q. Do you have any professional designations or memberships?

A. Yes, I do. I am a Certified Public Accountant (CPA) in accordance with the South Dakota Board of Accountancy, a member of the American Institute of Certified Public Accountants and a member of the South Dakota CPA society.

Q. Have you previously filed testimony in other natural gas rate proceedings before the South Dakota Public Utilities Commission?

A. Yes. I have filed testimony on behalf of Commission Staff relating to natural gas rate increases in Dockets NG98-011, NG99-002, NG01-010, NG02-011, NG04-001 and various other proceedings before the Commission.

Q. Are you familiar with Montana-Dakota Utilities Co.'s (MDU or Company) application for an increase in natural gas rates in South Dakota, Docket NG04-004?

A. Yes. I have reviewed the Company's prefiled testimony, exhibits, working papers and responses to data requests as it pertains to the issues that I am addressing.

Q. What is your role in this docket?

A. I am responsible for explaining Staff's approach to measuring MDU's South Dakota gas revenue requirement. I have prepared exhibits that summarize Staff's case. I have also prepared exhibits and will express opinions on the following specific revenue requirement issues:

<u>Rate Base:</u>

1. Historic Test Year amounts
2. Plant Additions and related Accumulated Depreciation
3. Accumulated Deferred Federal Income Tax
4. Accumulated Deferred Investment Tax Credit

<u>Operating Income:</u>

1. Historic Test Year Amounts
2. Revenue/Sales
3. Depreciation Expense – Plant Additions and Depreciation Rate changes
4. Ad Valorem Taxes
5. Postage Expense
6. Depreciation Study Expense
7. Uncollectible Accounts
8. Company Consumption
9. Office Supplies

10. Gain on the Sale of Plant
11. Interest Synchronization
12. Gross Receipts Tax (GRT)
13. Income Tax related items
14. Computer Rental
15. Telephone Expense

Staff witness Jacobson will provide testimony and exhibits regarding:

1. Labor
2. Benefits
3. Insurance
4. Contract Labor
5. Working Capital

Staff witness Farris will provide testimony and exhibits regarding:

1. Industry Dues
2. Advertising
3. Economic Development
4. Rate Case Expense

Staff witness Bettmann will provide testimony and exhibits regarding:

1. Annualizing Test Year Revenues to Current Rates (NG02-011)
2. Weather Normalization
3. Rate Design

Staff witness Copeland will provide testimony and exhibits regarding:

1. Capital Structure
2. Return on Equity

Staff witness Towers will provide testimony and exhibits regarding:

1. Depreciation Rates
2. Class Cost of Service

SUMMARY OF MDU'S CASE

Q. What is MDU requesting in Docket NG04-004?

A. MDU is requesting a pro forma revenue requirement of approximately $59,611,000. [1] This includes a requested rate of return on common equity of 11.0%. [2] More importantly, this represents a rate increase of approximately $1,282,000 [3] to its current South Dakota gas service rates that were established in Commission Docket NG02-011. MDU describes this as a 2.2% overall increase.[4] However, MDU includes projected purchased gas costs as a component of the calculated increase. Since purchased gas costs are recovered dollar for dollar through the Purchased Gas Adjustment (PGA) and are not a component of base rates, it is more appropriate to measure the general rate increase excluding purchased gas costs. Accordingly, MDU is seeking a 12.3% increase in its 2003 existing test year base rate revenues. [5]

Q. Is MDU requesting the increase for its entire South Dakota gas system?

A. No. MDU has two gas "systems" in South Dakota; the Black Hills gas system and the East River gas system. Each system is operated separately, has its own cost allocation, has its own individual and separate tariffs, etc. and thus, has individual and separate revenue requirements. MDU is only requesting a rate increase for the Black Hills gas system. Even though Staff and the Company often make reference to "South Dakota gas" we are referring to the Black Hills gas system.

Q. What is MDU's approach to measuring MDU's revenue requirement in this case?

A. Generally speaking, MDU starts with a twelve-month historic test year ending 12/31/03. MDU then adjusts the historic test year with 29 operating income pro forma adjustments[6] and nine additional rate base pro forma adjustments. [7]

Q. What are MDU's pro forma adjustments based on?

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[1] Statement M, page 8 of 8
[2] Testimony of J. S. Gaske, page 35, lines 3 – 7 and Statement G, page 2 of 2
[3] Testimony of Company President, Bruce T. Imsdahl, page 6, lines 1 - 3, Testimony of R. A. Mulkern, page 11, lines 6 - 9, and Statement M, page 8 of 8
[4] Statement O, page 1 of 1 and Testimony of Company President, Bruce T. Imsdahl , page 6, lines 7 – 14
[5] $1,2828,133 / ($44,201634 - $34,335,947)
[6] Statement M, pages 3 and 4 of 8
[7] Statement M, page 5 of 8

A. MDU indicates that the pro forma adjustments are "known and measurable," [8] but in reality MDU's pro forma adjustments are based on 2004 projected customer increases, [9] 2004 projected gas costs, [10] 2004 projected plant additions [11] and 2004 budgeted expenses. [12] As a result of these forecasts and projections, MDU ultimately labels the adjusted test period as "Pro Forma 2004." [13]

Q. Are you indicating that all of MDU's adjustments are based on forecasts, projections and budgets?

A. No. MDU proposes certain adjustments based on sound "known and measurable" principles, but many are based on projections, forecasts and budgets.

Q. Do you support MDU's use of forecast and projections?

A. No, I do not.

Q. Why not?

A. The objective of a rate case is to establish a per unit charge to recover the cost of service that reflects the appropriate matching of costs and investments to the revenue generated from that per unit charge. A projected test year, as opposed to a historic test year adjusted for known and measurable changes, is the result of a series of assumptions and estimates. Such a process cannot be considered as reliable as historical data for evaluating this revenue and cost relationship. Furthermore, projections can be speculative and difficult to verify for accuracy. Staff believes the use of incorrect projections is undesirable for ratemaking purposes. Therefore, Staff generally opposes the use of partially or fully forecasted or projected test years.

Q. Based on your education and experience, please describe what you believe is meant by the terms "known" and "measurable" as used in ARSD 20:10:13:44.

A. In general, to qualify as known and measurable, a cost of service item must be known as to its nominal amounts or costs, and its effect on the test year must be measurable. An

[8] Testimony of Rita A. Mulkern, page 2 line 13, page 3 line 15, page 9 line 21, page 10 line 1
[9] MDU Response No. 1-4, attachment A, support for Statement I, pages 54-55
[10] MDU Response No. 1-4, attachment A, support for Statement H, page 5
[11] Statement D
[12] MDU response No. 1-4, attachment A, support for Statement H, page 53-56
[13] Statement D, Schedule D-2, pages 3 and 4 of 4; Statement I, pages 2 and 3 of 10; and Statement N, Schedule N-1

adjustment is "measurable" when its effect on test year investment, expense and revenue relationships can be reasonably calculated.

Q. **Do you believe MDU's use of projections and forecasts meet the "known and measurable" criteria?**

A. No

Q. Please explain.

A. Again, projections, forecasts, assumptions and estimates are speculative. They are certainly not known. Additionally, many of the projections, forecasts, assumptions and estimates are made with little regard to the revenue/cost relationships; therefore, they are not measurable.

SUMMARY OF STAFF'S CASE

Q. What was Staff's approach to measuring MDU's revenue requirement in this case?

A. As in previous rate cases, Staff is measuring MDU's South Dakota gas revenue requirement on a recent historical twelve-month period (test year) basis. Staff's analysis of the South Dakota gas operation reflects a number of adjustments to MDU's revenues, expenses, and investments for that test year. These adjustments are made with the objective of conforming the test year to emulate normal, ongoing conditions, and to reflect cost and operational changes which are known and reasonably measurable.

Q. Do you believe Staff's method is an appropriate method for measuring the cost of service?

A. Yes, I do. Unquestionably, a historic test year is the actual measurement of the cost of service for that period. Additionally, a historic test year reflects a synchronized relationship among investments, costs and revenues. If one does a reasonably good job of adjusting the test year for known and measurable changes, one has updated the relationship that occurred during the test year to reflect current conditions. If one relies on the test year relationships which have been accurately adjusted, the results should produce fair and reasonable rates.

Q. Do you believe the use of a historic test year adjusted for known and measurable changes helps assure the company is operating efficiently?

A. Absolutely. In a monopoly environment, the use of a historic test year is one of the few effective tools the Commission has for assuring efficiency within the monopoly. Wall Street demands that the company control costs and be efficient in order to increase the bottom-line. If the company fails to be efficient and control costs, the bottom line suffers and the stock price falls. The use of a historic test year preserves this Wall Street mandated efficiency and uses it in setting rates. On the contrary, a projected test year allows a company to name the cost of service it desires.

Q. Has the Commission ever accepted a projected test year in rate setting?

A. To the best of my knowledge, Commission Staff has never recommended a revenue requirement, or accepted a company proposed revenue requirement that is based on a projected test year for an established company service territory. In fact, Staff has filed testimony in numerous cases to rebut and reject revenue requirements based on a projected test year. In these cases, Staff has offered a revenue requirement based on a historic test year adjusted for known and measurable changes. Additionally, the Commission, to the best of my knowledge, has never approved a projected test year in a rate case proceeding for an established company service territory. Furthermore, the Commission has issued a number of orders rejecting company proposed revenue requirements based on a projected test year. Therefore, Staff's revenue requirement, unlike MDU's, is in full compliance with past Commission practice.

Q. Have you prepared exhibits which summarize Staff's positions?

A. Yes. Staff Exhibit___(KAS-1), Schedule 3 lists Staff's positions on the specific issues relating to MDU's South Dakota, Black Hills gas operating income while Staff Exhibit___(KAS-2), Schedule 2 lists Staff's positions on specific issues relating to MDU's South Dakota, Black Hills gas rate base. Staff Exhibit___(KAS-1), Schedule 2 and Staff Exhibit___(KAS-2), Schedule 1 summarize these positions, while Staff Exhibit___(KAS-1), Schedule 1 calculates Staff's position on MDU's total revenue deficiency and revenue requirement.

Q. Based on analysis performed, has Staff found MDU's request for approximately $1,282,000 of additional revenue to be justified?

A. No. Staff's case indicates that the Company's request exceeds its requirement for additional revenue from South Dakota, Black Hills gas system customers. Specifically, Staff determined that a rate increase of $210,448 [14] allows the Company to recover its ongoing costs and allows for the opportunity to earn a reasonable and fair return on utility investment. Staff's recommendation includes an allowable rate of return on common equity of 9.25%.[15]

TEST YEAR AMOUNTS

Q. Did MDU file a historic test year with this case?

A. Yes. As stated earlier, MDU starts with a twelve-month historic test year ending 12/31/03.

Q. What did you use as a test year for Staff's case?

A. I also used a historic test year ending 12/31/03. This is sometimes referred to as "12/31/03 per books." I obtained the historic test year amounts from various Company statements, supporting schedules and Company responses to Staff data requests. Staff's historic test year amounts are found on Staff Exhibit___(KAS-1), Schedule 3, column b and Staff Exhibit___(KAS-2), Schedule 2, column b.

Q. Do your historic test year amounts agree with the Company historic test year amounts?

A. All my historic test year amounts that pertain to the operating income statement agree with MDU's amounts. However, my historic test year amounts that pertain to rate base differ.

Q. Why do they differ?

A. For the most part, the differences are due to the method used in calculating "average" rate base. MDU's average rate base amounts were derived from the beginning period (12/31/02) and the ending period (12/31/03) account balances. My average rate base

[14] Staff Exhibit___(KAS-1), Schedule 1, column b, line 10
[15] Testimony of Basil L. Copeland Jr. and Staff Exhibit___(BLC-1), Schedule 1, column d, line 3

amounts were the result of a 13 point average using the ending account balances for thirteen months.

Q. Please explain a thirteen-point average.

A. A thirteen-point average, in its simplest form, is derived from averaging the ending balances from thirteen consecutive months. The ending balances for the thirteen-month period captures the entire year's activity. In Staff's case, we used a test year starting January 1, 2003, and ending December 31, 2003. Since the 12/31/02 ending balance is also the 1/01/03 beginning balance, Staff has captured the entire year's activity using the thirteen-point average.

Q. Why did you use this thirteen-point average instead of MDU's average?

A. Historically the Commission has used thirteen-point averages, for rate base items because it better reflects the matching of costs, investments and revenues that I spoke of earlier.

Q. Please explain.

A. Under MDU's method, a plant item placed in service during the last month of a test year is inappropriately weighted as if it has been in service for six months. Since revenue is recorded as an accumulation of a year's activity, the books and records for that year would only reflect one month's worth of revenue generated from that plant, thus creating a mismatch. A thirteen-month average would weight that plant appropriately to better reflect the matching principle.

Q. Were you able to obtain Black Hills gas amounts for all rate base items?

A. No. MDU indicated that they were unable to obtain Black Hills gas utility amounts for customer deposits and the accumulated provision for injuries and damages.[16]

Q. What did you do?

A. The Company was able to provide South Dakota gas and electric utility amounts for customer deposits and total company gas and electric amounts for accumulated provision for injuries and damages. I allocated these amounts to Black Hills gas utility

[16] Company response to DR1-16 and 1-19

based on company revenue. A summary can be found on Staff Exhibit___(KAS-2) Schedule 3.

PLANT ADDITIONS

Q. Is MDU proposing any adjustments to plant?

A. Yes. MDU proposes adjustments to plant in service for budgeted and projected plant additions through 12/31/04.[17] Additionally, MDU is proposing to adjust the corresponding accumulated depreciation and depreciation expense for those projected plant additions and retirements.[18]

Q. Do you agree with MDU's method of adjusting plant?

A. No. MDU's plant adjustments are based on budgeted and/or projected plant additions. Thus, the plant adjustments do not conform to the known and measurable criteria.

Q. Are you proposing known and measurable plant adjustments to the historic test year?

A. I am proposing to annualize actual post test year non-revenue producing plant additions that have actually been placed in service and are used and useful. I am also adjusting depreciation expense and accumulated depreciation by the related amounts. This adjustment can be found on Staff Exhibit___(KAS-2) Schedule 7.

Q. Please explain what you mean by "non-revenue producing plant."

A. A plant item that is designed to serve new loads, provide additional service to existing loads, lower the cost by enhancing productivity or decrease operational expense through reducing maintenance or upkeep is revenue (operating income) producing. Additionally, a plant item may be deemed to be revenue producing if it increases cash inflow or decreases cash outflow other than the cash outflow for the cost of plant item. Non-revenue (non-operating income) producing plant does not produce any new revenue, cost savings or changes in cash flow.

[17] Statement D
[18] Statements E and J

Q. Why adjust only non-revenue producing plant additions?

A. Non-revenue producing plant additions are the only investments where the effect on the cost, investments and revenue relationships can be measured with reasonable certainty, thus fulfilling the requirements of the "matching principle."

DEFERRED FEDERAL INCOME TAX FOR PLANT ADDITIONS

Q. Have you reviewed MDU's adjustment to deferred federal income taxes for plant additions?

A. Yes.

Q. Please explain this adjustment.

A. Because of the differences in income tax depreciation and book depreciation, it is necessary to adjust the deferred federal income tax and the related accumulated provision for deferred income tax for the tax differences created by the two different depreciation rates on the plant additions. MDU adjusts for those differences based on MDU 2004 projected plant additions using the MDU new depreciation rates.[19]

Q. Do you agree with this adjustment?

A. I agree that an adjustment needs to be made. However, Staff disagrees with MDU's proposed deprecation rates and MDU's 2004 project plant additions.

Q. What are you proposing?

A. I propose an adjustment similar to MDU except I used Staff's plant additions and Staff's depreciation rates. This adjustment is found on Staff Exhibit___(KAS-2) Schedule 7.

ACCUMULATED DEFERRED INCOME TAX FOR NORMALIZATION FOR 2004

Q. IS MDU proposing an adjustment to the accumulated provision of deferred income tax for normalization for 2004.

A. Yes.

Q. Does Staff accept this adjustment?

A. No. MDU indicated that this adjustment is to make the accumulated provision for deferred income tax to reflect 2004 levels. [20] Staff believes this is not a proper known and measurable adjustment because it is based on 2004 pro forma projections. Therefore, Staff is not making this adjustment.

COST OF GAS

Q. Have you reviewed MDU's adjustment for cost of gas?

A. Yes.

Q. Please explain this adjustment.

A. MDU is proposing an increase in commodity charges of $11,747,188. [21] That represents a 34% increase for test year gas costs. [22] This increase is based on what MDU terms as "gas costs effective June 1, 2004, adjusted to reflect an annual gas cost for 2004," [23] or what I consider a 2004 projected cost of gas.

Q. Do you agree with MDU's adjustment?

A. No, I do not. First, commodity costs flow directly through the PGA. Except for a few minor adjustments that are correlated to the revenues related to gas cost (i.e. gross receipt tax, uncollectible accounts, etc.), the cost of gas will not affect the revenue deficiency. Second, MDU's adjustment attempts to project the cost of gas for the entire 2004 calendar year. Third, even if MDU's projection is accurate, an increase of 34% in gas cost will cause other changes in operating income that cannot be accurately measured. For example, customers may decrease usage due to conservation, better insulation, and possible fuel switching. For these reasons, Staff believes that MDU's adjustment to gas cost is not a known and measurable adjustment.

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[19] Statement K, page 8 and 14 of 16
[20] Telephone discussion with Rita Mulkern on 10/12/04
[21] Statement H Schedule H-1, page 3 of 21
[22] $11,747,188 / $34,335,947 – see Statement H Schedule H-1, page 3 of 21
[23] Testimony of Rita A. Mulkern, page 3, line 23 and page 4, line 1

Q. What are your proposing?

A. Staff chooses to leave gas costs at test year levels without adjusting.

SALES

Q. Is MDU proposing any adjustments to revenues?

A. Yes. MDU is proposing five adjustments to revenues.

Q. Please explain these adjustments.

A. MDU first adjusts revenues by applying current rates to 2003 test year sales volumes. Because of the timing of the implementation of distribution rates established in NG02-011, MDU's 2003 test year sales revenues include approximately eleven months of sales revenues under distribution rates prior to those established in NG02-011 and one month under current rates determined in NG02-011. Therefore, MDU's adjustment recalculates 2003 test year sales using NG02-011 distribution rates. This adjustment also included an increase for MDU's 2004 projected cost of gas. [24]

MDU's second revenue adjustment adjusted test year sales volumes for normal weather conditions at NG02-011 rates.[25]

MDU's third revenue adjustment annualizes customer numbers and related sales volumes to 2003 year end customer numbers.[26]

MDU's forth revenue adjustment adjusts customer numbers and related sales volumes for projected 2004 year-end customer numbers.[27]

MDU's fifth revenue adjustment includes late payment revenues in the cost of service.[28]

Q. Does Staff agree with these five adjustments?

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[24] Statement I, page 4 of 10
[25] Statement I, page 5 of 10
[26] Statement I, page 6 of 10
[27] Statement I, page 7 of 10
[28] Statement I, page 8 of 10

A. Staff agrees that 2003 test year sales revenues need to be adjusted for current rates established in NG02-011 and agrees that test year sales volumes need to be normalized for weather conditions. However, Staff disagrees with MDU regarding the increases in revenues for the 2004 projected cost of gas, the annualizing of customer numbers and volumes, and the increase in customer numbers and volumes to the 2004 projected year-end levels. Staff also disagrees with the inclusions of the late payment revenues.

Q. What are you proposing?

A. I am proposing one adjustment which adjusted 2003 sales revenue by the Staff's 2003 calculated weather normalized sales volumes at current rates. Staff witness Bettmann calculated the weather normalized test year sales volumes and then calculated 2003 revenue with those volumes at NG02-011 distribution rates. [29] I then subtracted the difference of the test year total sales revenues and the test year cost of gas from Staff witness Bettmann's distribution sales revenues to arrive at Staff's revenue adjustment for normal weather at NG02-011 distribution rates. This adjustment does not adjust test year cost of gas, and sales volumes due to changing customer counts. Staff's adjustment can be found on Staff Exhibit___(KAS-1) Schedule 8.

Q. Why not adjust the cost of gas?

A. As explained earlier, Staff does not believe that the cost of gas adjustment proposed by MDU is a known and measurable adjustment because the indirect operating income effect of a 34% increase in the cost of gas cannot be measured outside a test year.

Q. Why not adjust customer numbers as MDU did?

A. MDU annualized customer numbers and related sales volumes to 2003 year-end customer counts and then further adjusted customer numbers and related sales volumes to projected 2004 year-end customer counts. Staff disagrees with these adjustments because they are not proper known and measurable adjustments.

MDU's actual customer counts have been increasing slightly over time but within the course of a year, the customer counts tend to drop during the late spring and summer months and then increase during the late fall and winter months. [30]

[29] Staff Exhibit___(MCB-5) Schedule 5
[30] MDU monthly reports

MDU adjusts sales and the cost of gas but fails to reflect any additional operating income effect of the changing sales volumes due to the normal fluctuation in customer counts. These related operating income effects are impossible to measure outside the test year; therefore, they are not known and measurable. Furthermore, Staff does not accept the 2004 projected customer counts. Staff believes the relationship established within the test year between investments, costs and revenues is best left unadjusted when operating income effects cannot be measured.

Q. What does Staff propose regarding MDU's late payment revenue adjustment?

A. Staff proposed leaving these revenues below the line. This issue is addressed by Staff witness Jacobson.

AD VALOREM TAXES

Q. Did the Company propose an adjustment to Ad Valorem Taxes?

A. Yes. The Company calculated an Ad Valorem Tax increase based on MDU 2004 projected plant balances discussed above. More specifically, MDU calculated the effective Ad Valorem tax rate by function based on 12/31/03 average plant balances and the actual Ad Valorem taxes paid during 2003. MDU then multiplied the 2004 pro forma plant balances by this functional specific effective tax rate to obtain the pro forma Ad Valorem tax adjustment.[31]

Q. Do you agree with this adjustment?

A. I agree in theory that as plant balances increase MDU may pay higher ad valorem taxes. However, MDU's adjustment calculated the increase based on the 2004 pro forma plant which included plant addition that Staff has disallowed.

Q. Do you propose a known and measurable adjustment to Ad Valorem Taxes?

A. Yes. I propose a known and measurable adjustment using Staff's additions to plant multiplied by MDU's calculated effective Ad Valorem tax rate. This adjustment is summarized on Staff Exhibit___(KAS-1), Schedule 9.

ACCUMULATED DEFERRED INVESTMENT TAX CREDIT

Q. How is MDU accounting for the Accumulated Deferred Investment Tax Credit (ADITC)?

A. It is my understanding that MDU is amortizing the ADITC over 20 years.[32]

Q. Are you proposing an adjustment to ADITC?

A. Yes. During Staff's review of MDU's case, it was noted that MDU was amortizing the ADITC over a period shorter than the average service lives of the plant associated with the investment tax credit.[33] Staff's adjustment, as found on Staff Exhibit ___ (KAS-2), Schedule 6, restates the ADITC balance as if MDU has been amortizing the ADITC over the average service lives of the plant, which MDU indicates to be 26.0 years instead of 20 years. This adjustment conforms with Staff's previous treatment of MDU's ADITC.

Q. Why is this adjustment necessary?

A. MDU has been allowed certain tax credits. The only benefit the ratepayers receive from these tax credits is a deduction to rate base. Shortening the length of the amortization period would decrease the benefit the ratepayers receive from the investment tax credit. Furthermore, the rapid amortization does not match cost with the benefits. It would be improper to depreciate the cost of a plant item over a shorter period of time than its estimated useful life; likewise the benefit should also reflect the plant item's useful life.

DEPRECIATION EXPENSE

Q. Have you reviewed MDU's adjustment to depreciation expense?

A. Yes. Actually the company proposes two adjustments to depreciation expense both of which are related to updating depreciation rates.

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[31] Statement L, Schedule L-1, page 1 of 4
[32] MDU Response 1-23 and 1-23
[33] MDU Response 1-23 and 1-23

Q. Please explain these adjustments.

A. MDU has completed a depreciation study which indicates that depreciation rates MDU used in the 2003 test year need to be updated to better reflect remaining lives. MDU has implemented these rates in 2004.

The first of these adjustments adjusted the 2003 test year depreciation expense and accumulated depreciation to the 2004 depreciation rates. [34] The second adjustment adjusted depreciation and accumulated depreciation for vehicles and work equipment that is indirectly charged to O&M expense through clearing accounts. [35] Both adjustments were based on 2003 test year plant and 2004 pro forma plant additions.

Q. Do you agree with MDU's adjustments?

A. No. First, Staff disagrees with the depreciation rates that MDU used. Second, Staff disagrees with the pro forma plant additions (as discussed earlier).

Q. What are you proposing?

A. Staff witness Towers is providing testimony on what he believes are the appropriate depreciation rates. I have taken those depreciation rates and recalculated the depreciation amount (depreciation recorded to both depreciation expense and O&M expense) and the related accumulated depreciation for the test year average plant balances. This adjustment can be found on Staff Exhibit___(KAS-1), Schedule 5. I have also calculated the depreciation amount (depreciation recorded to both depreciation expense and O&M expense) and the related accumulated depreciation for plant additions. This adjustment can be found on Staff Exhibit___(KAS-2), Schedule 7.

DEPRECIATION STUDY

Q. Have you reviewed MDU's adjustment for the depreciation study?

A. Yes.

Q. Please explain this adjustment.

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[34] Statement J

A. In 2002 and 2003 MDU paid a consulting firm a total of $55,576.65 to conduct a depreciation study. According to MDU, the cost for this study has been coded to clearing accounts and has not yet been charged to the South Dakota gas expense accounts. [36] Since this is a non-recurring cost, MDU proposes to amortize the South Dakota Gas portion of this study, $15,249, over a five year period. [37] MDU has chosen not to include any of the unamortized balance in rate base.

Q. Do you agree with MDU's adjustment?

A. I agree that the cost of the depreciation study is a nonrecurring expense that is appropriately recovered over a period of time. Therefore, I have included MDU's adjustment on Staff Exhibit___(KAS-1) Schedule 3, column e.

COMPUTER RENTAL

Q. Have you reviewed MDU's adjustment for computer rental?

A. Yes.

Q. Please explain this adjustment.

A. MDU is proposing an adjustment which increases computer rental for an additional server that will be used in the operation of MDU's Geographic Information System. [38]

Q. Do you agree with MDU's adjustment?

A. No. MDU indicated that the GIS "benefits include more efficient engineering, tracking, and management of gas facilities by construction crews and region offices, reduced dependency on other departments for information, and timely and consistent data retrieval from a centralized database." [39] Because, it is impossible to measure the operating income effect of these efficiencies, I do not believe this is a proper known and measurable adjustment. The inclusion of the increase in rental expense without also accounting for the decrease in expenses caused by the efficiency violates the matching

[35] Statement H, Schedule H-1, page 8 of 21
[36] MDU Response 2-21, 3-6, 3-18
[37] Statement H, Schedule H-1, page 18 of 21 and MDU Response No.1-4, Attachment support for Statement H, pages 87 – 90
[38] Statement H, Schedule H-1, page 14 of 21

principle. Therefore, Staff has not accepted this adjustment. Furthermore, MDU has now indicated that the rental of the new GIS server has been pushed back until the first quarter of 2005. [40]

UNCOLLECTIBLE ACCOUNTS

Q. Have you reviewed MDU's adjustment for uncollectible accounts?

A. Yes.

Q. Please explain this adjustment.

A. MDU is proposing an adjustment which increases uncollectible accounts by 0.36% of the difference between test year and pro forma revenues. The 0.36% is based on a five year average of revenues and net write-offs. [41]

Q. Do you agree with MDU's adjustment?

A. In general, I do agree there is a correlation between uncollectible accounts and sales; as customers use more natural gas, or when the commodity charge increases, a gas distribution company will experience an increase in uncollectible accounts. I do not concede that this correlation is a direct one to one relationship in that if revenues increase by 10%, uncollectible accounts will increase by 10%. However, MDU used a five year average of the net direct write-offs to revenues, so this average would include an extended timeframe thus capturing both low and high percentage write-offs so I believe the 0.36% is a reasonable measure. Therefore, I agree with the theory of MDU adjustment, but I disagree with MDU's adjustment amount because MDU calculated the adjustment to uncollectible accounts based on MDU pro-forma revenues of $58,064,657, which included the 2004 projected cost of gas and 2004 projected customer numbers .

Q. What do you propose?

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[39] MDU Response 2-22b
[40] MDU Response 2-22c
[41] Statement H, Schedule H-1, page 13 of 21, and MDU Response No. 1-4, support for Statement H, page 58 - 59

A. I propose an increase to uncollectible accounts by 0.36% of Staff's adjustments to sales revenues. Additionally, I proposed increasing uncollectibles by 0.36% of the revenue deficiency. This adjustment can be found on Staff Exhibit ___(KAS-1) Schedule 7.

OFFICE SUPPLIES

Q. Have you reviewed MDU's adjustment to office supplies?

A. Yes.

Q. Please explain MDU's adjustment.

A. MDU proposed a $15,167 decrease to the 2003 test year office supplies expense. [42] MDU indicated that the decrease represented non-recurring purchases of software and software licenses purchased in 2003. [43]

Q. What are you proposing regarding office supplies?

A. Since this adjustment removed non-recurring expenses recorded in the 2003 test year, resulting in a better reflection on ongoing operations, I have included MDU's adjustment in Staff's case on Staff Exhibit___(KAS-1) Schedule 3, column f.

COMPANY CONSUMPTION

Q. Have you reviewed MDU's adjustment to company consumption?

A. Yes.

Q. Please explain MDU's adjustment.

A. MDU proposed an adjustment that increased the expense for natural gas that MDU consumes by 26.57%. MDU calculated this 26.57% increase by comparing the 2003 test year sales revenues to MDU's "Normalized" test year revenue. MDU calculated the normalized revenues by normalizing test year volumes for normal weather, and then

[42] Statement H, Schedule H-1, page 11 of 21
[43] MDU Response 2-27

calculated revenue using NG02-011 distribution rates and MDU 2004 projected cost of gas.

Q. Do you agree with MDU's adjustment?

A. Since the test year revenues reflect about 11 months under rates prior to NG02-011 and one month under current rate determined in NG02-011, I agree that company consumption needs to be increased by the increase in rates. I also agree that the volumes should be weather normalized. However, I disagree with using a 2004 projected cost of gas for the same reasons as listed earlier.

Q. What are you proposing for an adjustment?

A. I am proposing an increase for company consumption of 2.48%. Staff's adjustment can be found on Staff Exhibit___(KAS-1) Schedule 6.

Q. How did you arrive at the 2.48% increase?

A. I compared Staff's sales revenue increase for weather normalized volumes at NG02-011 rates to the test year sales revenue which represent a 2.48% increase.

Q. Explain the difference between MDU's 26.57% increase and your 2.48% increase.

A. The difference is due predominantly to the cost of gas used in each adjustment. MDU's 26.57% increase included the 2004 pro forma projected cost of gas where Staff's 2.48% increase used test year cost of gas.

TELEPHONE EXPENSE

Q. Have you reviewed MDU's adjustment to telephone expense?

A. Yes.

Q. Please explain MDU's adjustment.

A. MDU proposed an increase in telephone expense of $362. [44] MDU supported this increase with 2004 budgeted amounts [45] and indicated that the increase was "due to an increase in voice calls and cell phone usage..." [46]

Q. What are you proposing regarding this adjustment?

A. Since MDU indicated this increase was due to increased telephone usage, I do not believe it is a proper known and measurable adjustment. An increase in anticipated telephone usage, as opposed to an increase in telephone rates that MDU pays, violates the matching principle because one is unable to measure the additional direct or indirect effects on operating income that changes in usage may have. Therefore, I am not accepting MDU's adjustment to telephone expense.

POSTAGE EXPENSE

Q. Did you review MDU's postage expense adjustment?

A. Yes.

Q. Please explain MDU's adjustment.

A. MDU proposed a postage adjustment which decreased the test year postage expense by $4,692. [47] MDU made this adjustment because the 2003 test year amount recorded as postage expense included a meter fill charge in December of 2003 that is normally recorded in January. [48]

Q. What are you proposing in regard to the postage adjustment?

A. Since MDU's adjustment better reflects normal ongoing operations, I have included MDU's adjustment in Staff's case on Staff Exhibit___(KAS-1) Schedule 3, column d.

[44] Statement H, Schedule H-1, page 10 of 21
[45] MDU Response 1-4, support for Statement H, page 54
[46] MDU Response 2-28
[47] Statement H, Schedule H-1, page 9 of 21
[48] MDU Response 2-29

GAIN ON THE SALE OF PLANT

Q. Are you proposing an adjustment for the gain on the sale of plant?

A. Yes.

Q. Please explain your adjustment.

A. MDU's previous natural gas rate case, NG02-011, was approved by the Commission as a result of a settlement stipulation between Staff and MDU. In that settlement, Staff's case included an adjustment for a five year amortization for gains that MDU realized on the sale of certain plant items. A majority of the gain related to the sale of land and office building located in Rapid City. Staff's rationale provided for this adjustment in NG02-011 indicated that these plant items were previously rate base items supported and paid for by rate payers thus the rate payers should receive the benefits of any gain on sale. Since the gain set up in NG02-011 has not yet been fully amortized, the NG02-011 adjustment needs to be carried forward.

INTEREST SYNCHRONIZATION

Q. Have your reviewed MDU's proposed Interest Synchronization Adjustment?

A. Yes.

Q. Please explain this adjustment.

A. The MDU Interest Synchronization Adjustment [49] resulted in an adjustment to federal income tax. This adjustment was necessary to synchronize the tax deduction for interest on long term debt with the adjusted rate base and weighted cost of long-term debt.

Q. Do you agree with MDU's adjustment?

A. I agree with the method MDU used to calculate the adjustment. However, I did not agree with the calculation inputs or the actual amount of the adjustment.

Q. What are you proposing in regard to the Interest Synchronization Adjustment?

[49] Statement K, page 7 of 16

A. I am proposing an adjustment using Staff's historic test year rate base as adjusted for known and measurable changes and staff's weighted cost of long term debt. Staff's adjustment is found on Staff Exhibit ___(KAS-1), Schedule 4.

GROSS RECEIPTS TAX

Q. Have you prepared any gross receipts tax (GRT) adjustments?

A. Yes. Staff Exhibit ___(KAS-1), Schedule 3, line 23 calculates the GRT tax effect of all of Staff known and measurable adjustments. Staff Exhibit ___(KAS-1), Schedule 1, line 8 calculates the GRT effect of the Staff calculated Revenue Deficiency (Excess). Staff Exhibit ___(KAS-1), Schedule 10 adjusts the test year GRT expense to match MDU's reported test year revenues.

Q. Why is it necessary to adjust GRT?

A. MDU pays $0.0015 for each dollar of sales, transport and certain other miscellaneous revenues collected from South Dakota customers. Therefore, it is necessary to calculate the GRT effect of each known and measurable adjustment that Staff makes to MDU's revenues, including the income deficiency.

MDU is required to pay the GRT by July 15 of each year based on the revenues of the preceding calendar year. Therefore, the GRT paid and recorded in the 2003 test year is based on 2002 revenues. In order to appropriately match expenses with revenues, an adjustment is necessary to recalculate GRT using 2003 test year revenues.

Q. Does this conclude your testimony?

A. Yes.

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Revenue Requirement
Adjusted Test Year Ended December 31, 2003

Line	Description	Staff Proposed South Dakota - Gas Adjusted 2003 Test Year	MDU Proposed South Dakota - Gas Pro Forma 2004	Difference
	(a)	(b)	(c)	(d)
1	Average Rate Base	$ 17,081,188	$ 19,119,946	$ (2,038,758)
2	Adjusted Test Year Operating Income	1,355,789	1,006,537	349,252
3	Overall Rate of Return	7.937%	5.264%	
4	Rate of Return	8.734%	9.613%	
5	Required Operating Income	1,491,886	1,838,000	(346,114)
6	Income Deficiency (Excess)	136,097	831,463	(695,366)
7	Gross Revenue Conversion Factor	1.53846		
8	Revenue Deficiency (Excess)	209,380	1,280,210	(1,070,830)
9	Bad Debts on Revenue Deficiency (0.36%)	754		754
10	Gross Receipts Tax (at 0.0015)	314	1,923	(1,609)
11	**Total Revenue Deficiency (Excess)**	**210,448**	**1,282,133**	(1,071,685)
12	Adjusted Test Year Revenue	45,832,523	58,328,987	(12,496,464)
13	**Revenue Requirement**	**$ 46,042,971**	**$ 59,611,120**	$ (13,568,149)

SOURCES:
Column b, line 1: KAS-2, schedule 1, page 1, column d, line 32
Column b, line 2: KAS-1, schedule 2, page 1, column d, line 31
Column b, line 3: Line 2 divided by line 1
Column b, line 4: BLC-1, Schedule 1, column d, line 4
Column b, line 5: Line 1 * line 4
Column b, line 6: Line 5 less line 2
Column b, line 7: 35/65 + 1
Column b, line 8: Line 6 * line 7
Column b, line 9: Line 8 *0.36%
Column b, line 10: Line 8 * 0.0015
Column b, line 11: Line 8 plus line 9
Column b, line 12: KAS-1, schedule 2, page 1, column d, line 5
Column b, line 13: Line 11 plus line 10

Column c, lines 1 - 12: Statement M, page 8 of 8

Column d: Column b less column c

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Operating Income Statement With Known and Measurable Adjustments and Revenue Adjustment
Adjusted Test Year Ended December 31, 2003

Line No.	Description	South Dakota Per Books	Total Staff Adjustments	Adjusted Test Year	Revenue Adjustment	Adjusted Test Year with Revenue Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)
1	OPERATING REVENUES:					
2	Sales (480-485) (including unbilled)	$ 44,201,634	$ 1,094,695	$45,296,329	$ 210,448	$ 45,506,777
3	Transpiration (489) (including unbilled)	363,186	(43,613)	319,573		319,573
4	Other Revenues (488, 493, 495)	216,621	-	216,621		216,621
5	**TOTAL OPERATING REVENUES**	**44,781,441**	**1,051,082**	**45,832,523**	**210,448**	**46,042,971**
6	OPERATING EXPENSES:					
7	Operation and Maintenance:					
8	Natural Gas (accts 728, 804, 805, 808)	34,335,947	-	34,335,947		34,335,947
9	Labor	4,033,579	168,257	4,201,836		4,201,836
10	Benefits Expense	690,769	87,541	778,310		778,310
11	Insurance Expense	255,242	(3,643)	251,599		251,599
12	Uncollectible Account Expense	139,674	-	139,674		139,674
13	Regulatory Commission Expense	1,869	-	1,869		1,869
14	Other Operation and Maintenance	2,143,676	207,420	2,351,096		2,351,096
15	Total Operation and Maintenance	41,600,756	459,575	42,060,331	-	42,060,331
16	Depreciation and Amortization	1,815,584	(376,103)	1,439,481		1,439,481
17	Gain on Sale	-	(82,100)	(82,100)		(82,100)
18	Taxes:					
19	Property Taxes	388,906	-	388,906		388,906
20	Payroll Taxes					
21	FICA	272,985	15,177	288,162		288,162
22	Federal Unemployment	3,880	219	4,099		4,099
23	State Unemployment	10,598	269	10,867		10,867
24	Gross Receipts Tax	46,953	21,796	68,749	314	69,063
25	Federal Income Taxes	(1,118,415)	425,314	(693,101)	73,283	(619,818)
26	Deferred Income Taxes	997,246	(23,416)	973,830		973,830
27	Investment Tax Credit	-	-	-		-
28	Other Taxes	12,933	4,577	17,510		17,510
29	Total Taxes	615,086	443,936	1,059,022	73,597	1,132,619
30	**TOTAL OPERATING EXPENSES**	**44,031,426**	**445,308**	**44,476,734**	**73,597**	**44,550,331**
31	**OPERATING INCOME**	**$ 750,015**	**$ 605,774**	**$ 1,355,789**	**$ 136,851**	**$ 1,492,640**
32	Rate Base	17,836,071		$17,081,188		$ 17,081,188
33	Rate of Return	4.205%		7.937%		8.739%
34	Staff Proposed Rate of Return			8.734%		8.734%

SOURCES:

Line 5: Sum of lines 2 through 4
Line 15: Sum of lines 8 through 14
Line 29: Sum of lines 19 through 28
Line 30: Sum of lines 15, 16, 17, and 29
Line 31: Line 5 less line 30
Line 33: Line 31 / line 32
Line 34: BLC-1, Schedule 1
Column b: KAS-1, schedule 3, column b
Column b, line 32: KAS-2, Schedule 1, column b, line 32
Column c: KAS-1, schedule 3, column x
Column d: Column b plus column c
Column d, line 32: KAS-2, Schedule 1, column d, line 32
Column e, line 2: KAS-1, schedule 1, page 1, column b, line 11
Column e, line 24: KAS-1, schedule 1, page 1, column b, line 10
Column e, line 25: KAS-1, sch 1, p 1, col b, line 8 less KAS-1, sch 1, p 1, col b, line 6
Column f: Column d plus column e
Column f, line 32: KAS-2, Schedule 1, column d, line 32

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2003

Line No.	Description	South Dakota Per Books	Interest Sync	Postage Expense	Depreciation Study Expense	Office Suplies	Bad Debt	Company Consumption	Sale of Plant Assets (NG02-011)	Depr. Rate Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	OPERATING REVENUES:									
2	Sales (480-485) (including unbilled)	$ 44,201,634								
3	Transportation (489) (including unbilled)	363,186								
4	Other Revenues (488, 493, 495)	216,621								
5	**TOTAL OPERATING REVENUES**	**44,781,441**	-	-	-		-	-	-	-
6	OPERATING EXPENSES:									
7	Operation and Maintenance:									
8	Natural Gas (accts 804, 805, 808)	34,335,947								
9	Labor	4,033,579								
10	Benefits Expense	690,769								
11	Insurance Expense	255,242								
12	Uncollectible Account Expense	139,674								
13	Regulatory Commission Expense	1,869								
14	Other Operation and Maintenance	2,143,676		(4,692)	3,050	(15,167)	3,784	649		218,282
15	Total Operation and Maintenance	41,600,756	-	(4,692)	3,050	(15,167)	3,784	649	-	218,282
16	Depreciation and Amortization	1,815,584								(407,367)
17	Gain on Sale	-							(82,100)	
18	Taxes:									
19	Property Taxes	388,906								
20	Payroll Taxes									
21	FICA	272,985		-	-	-	-	-	-	-
22	Federal Unemployment	3,880		-	-	-	-	-	-	-
23	State Unemployment	10,598		-	-	-	-	-	-	-
24	Gross Receipts Tax	46,953		-	-	-	-	-	-	-
25	Federal Income Taxes (35%)	(1,118,415)	47,537	1,642	(1,068)	5,308	(1,324)	(227)	28,735	66,180
26	Deferred Income Taxes	997,246								
27	Investment Tax Credit	-								
28	Other Taxes	12,933								
29	Total Taxes	615,086	47,537	1,642	(1,068)	5,308	(1,324)	(227)	28,735	66,180
30	**TOTAL OPERATING EXPENSES**	**44,031,426**	**47,537**	**(3,050)**	**1,982**	**(9,859)**	**2,460**	**422**	**(53,365)**	**(122,905)**
31	**OPERATING INCOME**	**$ 750,015**	**$ (47,537)**	**$ 3,050**	**$ (1,982)**	**$ 9,859**	**$ (2,460)**	**$ (422)**	**$ 53,365**	**$ 122,905**
	Source		KAS-1, Sch 4	St. H, Sch. H-1 Page 9 of 21	St. H, Sch. H-1 Page 18 of 21	St. H, Sch. H-1 Page 11 of 21	KAS-1, Sch 7	KAS-1, Sch 6	NG02-011 Settlement	KAS-1 Sch 5
	Staff Witness Testimony	Senger	Senger	Senger	Senger	Senger	Senger	Senger	Senger	Senger/Towers
	Staff position on MDU's Adjustment	Adjusted	Adjusted	Accepted	Accepted	Accepted	Adjusted	Adjusted	Staff Proposed	Adjusted

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2003

ne o.	Description	Plant Additions	Tax Ad. Adjustment on Plant Additions	Distribution Rates and Weather Normalized	Industry Dues	Advertising	Economic Develoment	Rate Case Expense	Closing/Filing and Proir Period Adjustments	GRT on Test Year Revenues
	(a)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
1	OPERATING REVENUES:									
2	Sales (480-485) (including unbilled)			$ 1,094,695						
3	Transportation (489) (including unbilled)			(43,613)						
4	Other Revenues (488, 493, 495)									
5	**TOTAL OPERATING REVENUES**	-	-	1,051,082	-	-	-	-	-	-
6	OPERATING EXPENSES:									
7	Operation and Maintenance:									
8	Natural Gas (accts 804, 805, 808)									
9	Labor									
10	Benefits Expense									
11	Insurance Expense									
12	Uncollectible Account Expense									
13	Regulatory Commission Expense									
14	Other Operation and Maintenance	27,751			(31,301)	(32,142)	(776)	37,982		
15	Total Operation and Maintenance	27,751	-	-	(31,301)	(32,142)	(776)	37,982	-	-
16	Depreciation and Amortization	31,264								
17	Gain on Sale									
18	Taxes:									
19	Property Taxes									
20	Payroll Taxes									
21	FICA	-	-	-	-	-	-	-	-	-
22	Federal Unemployment	-	-	-	-	-	-	-	-	-
23	State Unemployment	-	-	-	-	-	-	-	-	-
24	Gross Receipts Tax	-	-	1,577	-	-	-	-	-	20,219
25	Federal Income Taxes (35%)	(41,702)	(1,602)	367,327	10,955	11,250	272	(13,294)	46,139	(7,077)
26	Deferred Income Taxes	21,047							(44,463)	
27	Investment Tax Credit									
28	Other Taxes		4,577							
29	Total Taxes	(20,655)	2,975	368,904	10,955	11,250	272	(13,294)	1,676	13,142
30	**TOTAL OPERATING EXPENSES**	38,360	2,975	368,904	(20,346)	(20,892)	(504)	24,688	1,676	13,142
31	**OPERATING INCOME**	$ (38,360)	$ (2,975)	$ 682,178	$ 20,346	$ 20,892	$ 504	$ (24,688)	$ (1,676)	$ (13,142)
	Source	KAS-2 Sch 7	KAS-1 Sch 9	KAS-1 Sch 8	MMF-1, Sch 1	MMF-1, Sch 2	MMF-1, Sch 3	MMF-1, Sch 4	Statement K Page 10 of 16	KAS-1 Sch 10
	Staff Witness Testimony	Senger	Senger	Bettmann/Senger	Farris	Farris	Farris	Farris	Senger	Senger
	Staff position on MDU's Adjustment	Adjusted	Adjusted	Adjusted	Adjusted	Adjusted	Staff Proposed	Updated	Accepted	Adjusted

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2003

ne lo.	Description	Labor	Benefits	Insurance Expense		Total Staff Adjustments	Adjusted Test Year
	(a)	(t)	(u)	(v)	(w)	(x)	(y)
1	OPERATING REVENUES:						
2	Sales (480-485) (including unbilled)					$ 1,094,695	$ 45,296,329
3	Transportation (489) (including unbilled)					(43,613)	319,573
4	Other Revenues (488, 493, 495)					-	216,621
5	**TOTAL OPERATING REVENUES**	-	-	-	-	1,051,082	45,832,523
6	OPERATING EXPENSES:						
7	Operation and Maintenance:						
8	Natural Gas (accts 804, 805, 808)					-	34,335,947
9	Labor	168,257				168,257	4,201,836
10	Benefits Expense		87,541			87,541	778,310
11	Insurance Expense			(3,643)		(3,643)	251,599
12	Uncollectible Account Expense					-	139,674
13	Regulatory Commission Expense					-	1,869
14	Other Operation and Maintenance					207,420	2,351,096
15	Total Operation and Maintenance	168,257	87,541	(3,643)	-	459,575	42,060,331
16	Depreciation and Amortization					(376,103)	1,439,481
17	Gain on Sale					(82,100)	(82,100)
18	Taxes:						
19	Property Taxes					-	388,906
20	Payroll Taxes						
21	FICA	15,177	-	-	-	15,177	288,162
22	Federal Unemployment	219	-	-	-	219	4,099
23	State Unemployment	269	-	-	-	269	10,867
24	Gross Receipts Tax	-	-	-	-	21,796	68,749
25	Federal Income Taxes (35%)	(64,373)	(30,639)	1,275	-	425,314	(693,101)
26	Deferred Income Taxes					(23,416)	973,830
27	Investment Tax Credit					-	-
28	Other Taxes					4,577	17,510
29	Total Taxes	(48,708)	(30,639)	1,275	-	443,936	1,059,022
30	**TOTAL OPERATING EXPENSES**	119,549	56,902	(2,368)	-	445,308	44,476,734
31	**OPERATING INCOME**	$ (119,549)	$ (56,902)	$ 2,368	$ -	$ 605,774	$ 1,355,789
	Source	DAJ-2, Sch 2	DAJ-2, Sch 3	DAJ-2, Sch 1			
	Staff Witness Testimony	Jacobson	Jacobson	Jacobson			
	Staff position on MDU's Adjustment	Adjusted	Adjusted	Adjusted			

Montana Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Operating Income Statement With Known and Meaurable Adjustments
Adjusted Test Year Ended December 31, 2003

SOURCES:

Line 5:	Sum of lines 2 through 4
Line 15:	Sum of lines 8 through 14
Line 21:	Line 9 * 0.0902
Line 22:	Line 9 * 0.0013
Line 23:	Line 9 * 0.0016
Line 24 (excl col s):	Line 5 * 0.0015
Line 25 (exc col. c & r):	(line 5 less sum of (lines 15, 16, 17, 19, 21 through 24, 28))*.35
Line 29:	Sum of lines 19 through 28
Line 30:	Sum of lines 15, 16, 17 and 29
Line 31:	Line 5 less line 30
Column b, line 2:	Sum of: Statement I, page 9 of 10, Residential Sales - $23,626,622, Firm Gen Sales - $16,357,687, Air Force Sales - $2,283,008, Small Interruptible Sales - $215,388, Large Interruptible Sales - $399,602, and Statement I, page 1 of 10, Unbilled Rev (sales) - $1,319,327
Column b, line 3:	Sum of: Statement I, page 9 of 10, Small Interruptible Transport - $210,676, Large Interruptible Transport - $159,119, and Statement I, page 1 of 6, Unbilled Rev (Transport) ($6,609)
Column b, line 4:	Statement I, page 1 of 10
Column b, line 8:	Statement H, page 2 of 3 and Schedule H-1, page 20 of 21
Column b, line 9:	Statement H, Schedule H-1, page 20 of 21
Column b, line 10:	Statement H, Schedule H-1, page 20 of 21
Column b, line 11:	Statement H, Schedule H-1, page 20 of 21
Column b, line 12:	Statement H, Schedule H-1, page 21 of 21
Column b, line 13:	Statement H, Schedule H-1, page 21 of 21
Column b, line 14:	Sum of: Statement H, Schedule H-1, Page 20 of 21, Contract Labor - $691,086, vehicles and Work Equipment - $281,031, postage - $160,126, telephone - $103,085, page 21 of 21 office supplies - $103,452, Company Consumption - $37,435, Computer Rental - $40,453, Industry Dues - $42,948, Advertising - $44,223 and All Other O&M - $639,837
Column b, line 16:	Statement J, page 1 of 8
Column b, line 19:	Statement L, page 1 of 1
Column b, line 21:	Statement L, page 1 of 1
Column b, line 22:	DR1-4, support for Statement L, page 1
Column b, line 23:	DR1-4, support for Statement L, page 1
Column b, line 24:	Statement L, page 1 of 1
Column b, line 25:	Statement K, page 5 of 16
Column b, line 26:	Statement K, page 12 of 16
Column b, line 27:	
Column b, line 28:	Statement L, page 1 of 1, Sum of: Delaware Franchise - $12,682, Highway Use Tax - $111, Secretary of State - $137
Column c, line 25:	KAS-1, Schedule 4, column b, line 6
Column d, line 14:	Statement H, Schedule H-1, page 9 of 21
Column e, line 14:	Statement H, Schedule H-1, page 18 of 21
Column f, line 14:	Statement H, Schedule H-1, page 11 of 21
Column g, line 14:	KAS-1 Schedule 7, column d, line 3
Column h, line 14:	KAS-1 Schedule 6, column f, line 6

Montana-Dakota Utilities Co.
Docket NG04-004
Interest Synchonization Adjustment
Adjusted Test Year Ended December 31, 2003

Line	**Description**	**Amount**	
	(a)	(b)	
1	Investment To Be Financed (Average Rate Base)	$ 17,081,188	
2	Weighted Cost of Long Term Debt	3.959%	
3	Synchronized Interest Expense	676,166	
4	Interest Expense as filed	811,985	
5	Difference In Interest Expense	(135,819)	
6	Federal Income Tax Adjustment (35%)	**$ 47,537**	To KAS-1, Sch 3, col c, line 25

SOURCES:
Column b, line 1: KAS-2, schedule 1, page 1, column d, line 32
Column b, line 2: BLC-1, schedule 1,column e, line 1
Column b, line 3: Line 1 times line 2
Column b, line 4: Statement K, page 5 of 16
Column b, line 5: Line 3 less line 4
Column b, line 6: line 7 times 35% (inverse)

Montana-Dakota Utilities Co.
Docket NG04-004
Depreciation Adjustment
Adjusted Test Year Ended December 31, 2003

	Description	Amount	Amount	Amount	Sources
	(a)	(b)	(c)	(d)	(e)
1	**DEPRECIATION**				
2	2003 Calculated Depreciation with New Rates			1,408,217	KAS-1 Sch 5, page 2, col f, line 63
3	2003 Test year Depreciation (actual)			1,815,584	KAS-1 Sch 3, col b, line 16
4	**Difference - Staff Adjustment to Depreciation**			(407,367)	To KAS-1 Sch 3, col j, line 16
5	**DEPRECIATION CHARGE TO O&M**				
6	2003 Calculated Veh. Depr. w/ new rates to clearing accts				
7	General Plant				
8	392.1 Transportation Equip, Non-Un.	1,563			KAS-1 Sch 5, p 2, col g, line 21
9	392.2 Transportation Equip, Unitized	373,330			KAS-1 Sch 5, p 2, col g, line 22
10	Common Plant				
11	392.1 Trans. Equip., Non-Unitized	-			KAS-1 Sch 5, p 2, col g, line 48
12	392.2 Trans. Equip., Unitized	7,910			KAS-1 Sch 5, p 2, col g, line 49
13	Total2003 Calculated Veh. Depr. w/ new rates to clearing accts		382,803		Sum of col b line 8 through 12
14	2003 % of Vehicle Depr. charged to O&M (actual)		82.56%		MDU Response 1-4, Att. A, Support for St. H, p 48
15	2003 Vehicle Depreciation In O&M (new rates)		316,042		Col c line 13 * col c line 14
16	2003 Calculated Work Equip. Depr. w/ new rates to clearing accts				
17	General Plant				
18	394.2 Tools,Shop&Gar. Equip.-Unitized	1,139			KAS-1 Sch 5, p 2, col g, line 25
19	396.1 Work Equipment Trailers	5,563			KAS-1 Sch 5, p 2, col g, line 38
20	396.2 Power Operated Equip.	-			KAS-1 Sch 5, p 2, col g, line 39
21	Common Plant				
22	396.2 Power operating equipment	69			KAS-1 Sch 5, p 2, col g, line 55
23	Total 2003 Calculated Work Equip. Depr. w/ new rates to clearing accts		6,771		Sum of col b line 18 through 22
24	2003 % of Work Equipment Depr. charged to O&M (actual)		16.44%		MDU Response 1-4, Att. A, Support for St. H, p 51
25	2003 Work Equipment Depreciation In O&M (new rates)		1,113		Col c line 23 * col c line 24
26	2003 Total Vehicle and Work Equip. Depr. In O&M (new rates)			317,155	Col c line 15 plus col c line 25 (MDU Res 1-4 Att. A, H p 45)
27	2003 Vehicle Depr. charged to clearing accounts (actual)		106,568		MDU Response 1-4, Att. A, Support for St. H, p 47
28	2003 % of Vehicle Depr. charged to O&M (actual)		82.56%		MDU Response 1-4, Att. A, Support for St. H, p 48
29	2003 Vehicle Depreciation In O&M (actual)		87,983		Col c line 27 * col c line 28
30	2003 Work Equipment Depr. charged to clearing accounts (actual)		66,241		MDU Response 1-4, Att. A, Support for St. H, p 50
31	2003 % of Work Equipment Depr. charged to O&M (actual)		16.44%		MDU Response 1-4, Att. A, Support for St. H, p 51
32	2003 Work Equipment Depreciation In O&M (actual)		10,890		Col c line 30 * col c line 31 (MDU DR1-4 Att. A, H p 46)
33	2003 Test Year Total Vehicle and Work Equip. Depr. In O&M (actual)			98,873	col c line 29 + col c line 32
34	**Difference - Staff Adjustment to Depreciation Charged to O&M**			218,282	col d line 26 less col d line 33
				To KAS-1 Sch 3 Col j, line 14	

35 **ACCUMULATED DEPRECIATION**

	Description	Test Year Beginning Balance (1/1/03)	Calculated Average 2003 Increase (new rates)	Adjusted 2003 Test Year Average Balance	2003 Test Year Average Balance (Actual)	Staff Adjustment to Accum Depr.	
36	(a)	(b)	(c)	(d)	(e)	(f)	
37	Distribution (including Intangible)	20,849,011	457,382	21,306,393	21,493,907	(187,514)	To KAS-2, Schedule 3
38	General (including Intangible)	2,663,566	333,402	2,996,968	2,130,202	866,766	column d, lines 9, 10 and 11
39	Common (including Intangible)	998,617	114,812	1,113,429	1,122,147	(8,718)	
40	Total Accumulated Depreciation	24,511,194	905,596	25,416,790	24,746,256	670,534	

Sources:
Column b line 37 - 40: KAS-2 Sch 5, Column b, lines 16, 40, 63 and 64
Column c line 37 - 40: KAS-1 Sch 5, page 2 Column i, lines 15, 39, 63 and 64
Column d line 37 - 40: Column b plus column c
Column e line 37 - 40: KAS-2 Sch 5, Column o, lines 16, 40, 63 and 64
Column f line 37 - 40: Column d minus column e

Montana-Dakota Utilities Co.
Docket NG04-004
Depreciation Adjustment
Adjusted Test Year Ended December 31, 2003

	Acct. No.	Account	Staff Calculated 13 Point 2003 Average Plant Balance	Staff Proposed Depreciation Rates	Notes	Annual Depreciation (new rates)	Depreciation Charged To Clearing Acct. (new rates)	Annual Accumulated Depreciation (new rates)	Average Accumulated Depreciation (new rates)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1		Distribution Plant							
2	374.1	Land	30,129	0.00%		-		-	-
3	374.2	Rights of Way	8,609	0.75%		65		65	33
4	375	Structures & Improvements	38,219	2.57%		982		982	491
5	376	Mains	18,518,533	1.92%		355,556		355,556	177,778
6	378	Meas & Reg Equip-General	251,211	2.96%		7,436		7,436	3,718
7	379	Meas & Reg Equip-City Gate	67,742	3.54%		2,398		2,398	1,199
8	380	Services	5,532,491	5.66%		313,139		313,139	156,570
9	381	Positive Meters	6,173,167	3.19%		196,924		196,924	98,462
10	383	Service Regulators	865,844	2.59%		22,425		22,425	11,213
11	385	Ind Meas & Reg Sta Eqpt	63,429	3.04%		1,928		1,928	964
12	386	Other Property on Cust. Premise	170,931	5.19%		8,871		8,871	4,436
13	387.1	Cathodic Protection Equip.	66,245	5.75%		3,809		3,809	1,905
14	387.2	Other Distribution Equip.	86,342	1.42%		1,226		1,226	613
15	**Total Distribution Plant**		**31,872,892**			**914,759**	**-**	**914,759**	**457,382**
16		General Plant							
17	389	Land	581,077	0.00%				-	-
18	390	Structures and Improvements	3,770,356	3.73%		140,634		140,634	70,317
19	391.1	Furniture & Fixtures	293,013	4.97%		14,563		14,563	7,282
20	391.3	Computer Equip.-PC	233,798	26.13%		61,091		61,091	30,546
21	392.1	Transportation Equip, Non-Un.	35,859	4.36%	C/A		1,563	1,563	782
22	392.2	Transportation Equip, Unitized	1,766,826	21.13%	C/A		373,330	373,330	186,665
23	393	Stores Equipment	53,337	2.49%		1,328		1,328	664
24	394.1	Tools,Shop&Gar. Equip.-Non-Un.	473,589	6.62%		31,352		31,352	15,676
25	394.2	Tools,Shop&Gar. Equip.-Unitized	47,474	2.40%	C/A		1,139	1,139	570
26	394.3	Vehicle Maintenance Equip.	7,627	5.78%		441		441	221
27	394.4	Vehicle Refueling Equip.	116,020	4.72%		5,476		5,476	2,738
28	395	Laboratory Equipment	35,789	7.67%		2,745		2,745	1,373
29	396.1	Work Equipment Trailers	96,572	5.76%	C/A		5,563	5,563	2,782
30	396.2	Power Operated Equip.	1,368,641	0.00%	C/A		-	-	-
31	397.1	Radio Comm. Equip.-Fixed	97,627	7.37%		7,195		7,195	3,598
32	397.2	Radio Comm. Equip.-Mobile	126,297	7.34%		9,270		9,270	4,635
33	397.3	General Tele. Comm. Equip.	40,865	9.88%		4,037		4,037	2,019
34	397.5	Supervisory & Tele. Equip.	58,754	0.25%		147		147	74
35	397.6	Scada System	533	0.00%		-		-	-
36	397.8	Network Equipment	22,243	26.26%		5,841		5,841	2,921
37	398	Miscellaneous Equipment	25,915	1.27%		329		329	165
38	303	Intangible Plant - General	138,426	0.54%		748		748	374
39	**Total General Plant (including intangible)**		**9,390,638**			**285,197**	**381,595**	**666,792**	**333,402**
40		Common Plant							
41	389	Land	35,627	0.00%		-		-	-
42	390	Structures and Improvements	445,057	2.93%		13,040		13,040	6,520
43	391.1	Furniture & Fixtures	163,704	4.95%		8,103		8,103	4,052
44	391.2	Computer Equipment-Bull/AS400	5,593	1.52%		85		85	43
45	391.3	Computer Equip.-PC	239,208	23.29%		55,712		55,712	27,856
46	391.4	Computer Equip. - Other (EMS)	445	0.00%		-		-	-
47	391.5	Computer Equip.-Other	47,087	0.46%	F/D		-	-	-
48	392.1	Trans. Equip., Non-Unitized	1,852	0.00%	C/A	-	-	-	-
49	392.2	Trans. Equip., Unitized	59,343	13.33%	C/A		7,910	7,910	3,955
50	392.3	Aircraft	325,414		C/A	-	13,373	13,373	6,687
51	393	Stores Equip.	320	2.80%		9		9	5
52	394.1	Tools, Shop and Garage Equip.	2,263	6.11%		138		138	69
53	394.3	Vehicle Maint. Equip.	7,311	4.75%		347		347	174
54	394.4	Vehicle Refueling Equip.	8,270	4.38%		362		362	181
55	396.2	Power operating equipment	2,555	2.69%	C/A		69	69	35
56	397.1	Radio Comm. Equip.-Fixed	13,882	4.99%		693		693	347
57	397.2	Radio Comm. Equip.-Mobile	21,278	4.08%		868		868	434
58	397.3	General Tele. Comm. Equip.	33,033	8.72%		2,880		2,880	1,440
59	397.5	Supervisory & Tele. Equip.	177	0.35%		1		1	1
60	397.8	Network Equipment	51,045	17.95%		9,163		9,163	4,582
61	398	Miscellaneous Equipment	35,165	2.41%		847		847	424
62	303	Intangible Plant - Common	1,232,872	9.41%		116,013		116,013	58,007
63	**Total Common Plant including intangible**		**2,731,501**			**208,261**	**21,352**	**229,613**	**114,812**
64		**Total Gas Plant in Service**	**43,995,031**			**1,408,217**	**402,947**	**1,811,164**	**905,596**

NOTES: C/A = Depreciation charged to a clearing account - see Statement J, page 2 & 3 of 8
F/D = Account is fully depreciated - See Statement J, page 2 & 3 of 8

Sources:

Column c: KAS-2 Sch 4, column q
Column d: Staff Witness Bob Towers (ND rates)
Column f: Column c * column d
Column g: Column c * column d
Column h: Column f plus Column g
Column i: Column h divided by 2 (average balance)

Montana-Dakota Utilities Co.
Docket NG04-004
Company Consumption
Adjusted Test Year Ended December 31, 2003

MDU 2003 GAS SALES

	Description	2003 Test Year	Weather Norm Adjustment at Current Rates	Adjusted	% Change
	(a)	(b)	(c)	(d)	(e)
1	**Sales Revenues**	$ 44,201,634	$ 1,094,695	$ 45,296,329	2.48%

MDU GAS USAGE

		2003 Test Year (per books)				Difference Staff
		Gas Utility	South Dakota	% Change	Adjusted Test Year	Adjustment
2	**Distribution**	125,221	14,048	102.48%	14,396	348
3	**Customer Accounting**	33,884	6,147	102.48%	6,299	152
4	**Sales**	6,207	863	102.48%	884	21
5	**A&G**	24,692	5,181	102.48%	5,309	128
6	**Total**	190,004	26,239		26,888	**649**

To KAS-1
Sch 3, col h
line 14

SOURCES:

Column b, line 1:	KAS-1, Schedule 3, column b, line 2
Column c, line 1:	KAS-1, Schedule 3, column m, line 2
Column d, line 1:	Sum of columns b & c
Column e, line 1:	Column c / column b
Column b & c, lines 2 - 6:	MDU Response 1-4, Attachment A, Schedule H page 57
Column d, lines 2 - 6:	1 plus column e, line 1
Column e, lines 2 - 6:	Column c * column d
Column f, lines 2 - 6:	Column e less column c

Montana-Dakota Utilities Co.
Docket NG04-004
Uncollectible Accounts
Adjusted Test Year Ended December 31, 2003

	Description	Staff's Adjustments to Test Year Revenue	Five year Average Write off %	Adjustments To Test Year Revenues	
	(a)	(b)	(c)	(d)	
1	Sales	1,094,695	0.36%	3,941	
2	Transport	(43,613)	0.36%	(157)	
3			TOTAL	**3,784**	To KAS-1, Sch 3, col g, line 14

		Revenue Deficiency	Five year Average Write off %	Bad Debt Adjustment On Staff's Revenue Deficiency	
4		209,380	0.36%	**754**	To KAS-1, Sch 1, col b, line 9

SOURCES:

Column b, line 1: KAS-1, Schedule 3, column x, line 2
Column b, line 2: KAS-1, Schedule 3, column x, line 3
Column c, lines 1, 2 and 4: MDR Response 1-4, Attachment A, support of Schedule H, p 58
Column d, line 1 and 2: column b * column c
Column b line 4: KAS-1, Schedule 1, column b, line 8
Column d, line 4: column b * column c

Montana-Dakota Utilities Co.
Docket NG04-004
Revenue - Weather Norm at Current Rates
Adjusted Test Year Ended December 31, 2003

	(a)	Test Year Dekatherms Adjusted for Weather Normalized and Unbilled (b)	Amount (c)	Distribution Revenues at NG02-011 Distribution Rates on Adjusted Volumes (d)	(e)
	Sales				
1	Residential	3,035,759		7,683,206	
2	Firm General Service	2,076,428		2,984,424	
3	Firm Contract Service	641,741		225,126	
4	Interruptible (small & large)	110,220		32,377	
5	Ellsworth Air Force Base	550,146		35,249	
6	TOTAL	6,414,294		10,960,382	
7	Test Year Actual Per Book Revenues				
8	Sales (480-485)		44,201,634		
9	Less Test Year Gas		34,335,947		
10	Test Year Distribution rates			9,865,687	
11	Difference - Staff Rev Adjustment				
12	Weather Norm at NG02-011 Dist rates			**1,094,695**	To KAS-1, Sch 3 col m, line 2

		Test Year Dekatherms Adjusted for Weather Normalized and Unbilled	Distribution Revenues at NG02-011 Distribution Rates on Adjusted Volumes	Test Year Revenues	Staff Adjustment	
13	**Transport**					
14	Interruptible Transport (small & large)	889,088	319,573	363,186	**(43,613)**	To KAS-1, Sch 3 col m, line 2

Sources:

Column b & d, lines 1 through 6 and 14:	MCB-5, Schedule 1, page 1
Column c, line 8:	KAS-1, schedule 3, column b, line 2
Column c, line 9:	KAS-1, schedule 3, column b, line 8
Column c, line 10:	Column c, line 8 less line 9
Column d line 12:	Column d, line 6 less line 10
Column d, line 14:	KAS-1, schedule 3, column b, line 3
Column e, line 14:	Column c less column d

Montana-Dakota Utilities Co.
Docket NG04-004
Ad Valorem Tax
Adjusted Test Year Ended December 31, 2003

	Description	Plant Additions	2003 Effective Ad Valorem Tax Rate	Ad Valorem Tax Adjustment	
	(a)	(b)	(c)	(d)	
1	**Distribution**	$ 104,482	0.9328%	$ 975	
2	**General**	287,169	0.7354%	2,112	
3	**General Intangible**		0.0675%	-	
4	**Common**	79,943	1.7117%	1,368	
5	**Common Intangible**	180,110	0.0675%	122	
6	**TOTAL**	$ 651,704		**$ 4,577**	To KAS-1 Sch 3 col I, line 28

Column b: KAS-2, Schedule 7, column g
Column c: Statement L, Schedule L-1, page 1 of 4, column, "Effective Tax Rate"
Column d: Column b * column c

Montana-Dakota Utilities Co.
Docket NG04-004
Gross Receipts Tax
Adjusted Test Year Ended December 31, 2003

Line	Description	South Dakota Per Books Test Year	Gross Receipts TAX 0.15%	
	(a)	(b)	(c)	
1	Sales	$ 44,201,634	$ 66,302	
2	Transportation	363,186	545	
3	Other Revenue	216,621	325	
4	TOTAL	44,781,441	67,172	
5	Test Year GRT		46,953	
6	Difference (Staff Adjustment)		**$ 20,219**	To KAS-1, Sch 3 col s, line 24

NOTE: Gross Receipt tax on revenue adjustments and revenue requirement are calculated individually with adjustment.

SOURCES:
Column b: KAS-1, Schedule 3, column b, line 3, 4 and 5
Column c, lines 1 - 3: column b * 0.15% - gross receipt tax amount
Column c, line 5: KAS-1 Schedule 3, column b, line 24

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2003

Line No.	Description	South Dakota Test Year Average Per Books	Total Pro Forma Adjustments	South Dakota Pro Forma Rate Base
	(a)	(b)	(c)	(d)
1	Gas Plant in Service (101)			
2	Distribution (including Intangible - 303)	$ 31,872,892	$ 104,482	$ 31,977,374
3	General (including Intangible - 303)	9,390,638	287,169	9,677,807
4	Common (including Intangible 303)	2,731,501	260,053	2,991,554
5	Total Gas Plant in Service (101)	43,995,031	651,704	44,646,735
6	Gas - Completed Construction Not Classified (106)	446,103	-	446,103
7	Total Plant in Service (101 and 106)	44,441,134	651,704	45,092,838
8	Accumulated Depreciation			
9	Distribution (including Intangible)	21,493,907	(186,510)	21,307,397
10	General (including Intangible)	2,130,202	883,549	3,013,751
11	Common (including Intangible)	1,122,147	5,941	1,128,088
12	Total Accumulated Depreciation	24,746,256	702,980	25,449,236
13	TOTAL NET GAS PLANT IN SERVICE	19,694,878	(51,276)	19,643,602
14	Additions to Rate Base:			
15	Material and Supplies	271,563	(7,075)	264,488
16	Fuel Stocks	-	-	-
17	Prepayments	76,422	25,865	102,287
18	Advanced Tax Collection	-	(95,375)	(95,375)
19	Working Capital	-	(390,228)	(390,228)
20	Other	150,700	88,728	239,428
21	TOTAL ADDITIONS TO RATE BASE	498,685	(378,085)	120,600
22	Deductions to Rate Base:			
23	Accumulated Deferred Income Taxes	1,921,358	21,047	1,942,405
24	Accumulated Investment Tax Credit	21,525	103,290	124,815
25	Customer Advances for Construction	57,168	(4,064)	53,104
26	Customer Deposits	159,060	-	159,060
27	Accumulated Provision for Uncollectibles	42,404	-	42,404
28	Accumulated Provision for Injuries and Damages	155,977	-	155,977
29	Miscellaneous Operating Provisions	-	-	-
30	Other	-	205,249	205,249
31	TOTAL DEDUCTIONS TO RATE BASE	2,357,492	325,522	2,683,014
32	**TOTAL SOUTH DAKOTA RATE BASE**	**$ 17,836,071**	**$ (754,883)**	**$ 17,081,188**

Sources:

Line 5: Sum of lines 2 through 4
Line 7: Line 5 plus line 6
Line 12: Sum of lines 9 through 11
Line 13: Line 7 less line 12
Line 21: Sum of lines 15 through 20
Line 31: Sum of lines 23 through 30
Line 32: Line 13 plus 21 less line 31
Column b: KAS-2 Schedule 2, page 1, column b
Column c: KAS-2 Schedule 2, page 1, column j
Column d: column b plus column c

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2003

Line No.	Description	South Dakota Test Year Average Per Books	Investment Tax Credits	Depreciation Rate Change	Plant Additions	Updates and Working Capital	Average Unamortized Rate Case Expense	Unamortized Balance Gain on Sale (NG02-012)	Total Staff Adjustments	Total Staff South Dakota Rate Base
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Gas Plant in Service (101)									
2	Distribution (including Intangible - 303)	$ 31,872,892			104,482				104,482	$ 31,977,374
3	General (including Intangible - 303)	9,390,638			287,169				287,169	9,677,807
4	Common (including Intangible 303)	2,731,501			260,053				260,053	2,991,554
5	Total Gas Plant in Service (101)	43,995,031	-	-	651,704	-	-	-	651,704	44,646,735
6	Gas - Completed Construction Not Classified (106)	446,103							-	446,103
7	Total Gas Plant in Service (101 and 106)	44,441,134	-	-	651,704	-	-	-	651,704	45,092,838
8	Accumulated Depreciation									
9	Distribution (including Intangible)	21,493,907		(187,514)	1,004				(186,510)	21,307,397
10	General (including Intangible)	2,130,202		866,766	16,783				883,549	3,013,751
11	Common (including Intangible)	1,122,147		(8,718)	14,659				5,941	1,128,088
12	Total Accumulated Depreciation	24,746,256	-	670,534	32,446	-	-	-	702,980	25,449,236
13	TOTAL NET GAS PLANT IN SERVICE	19,694,878	-	(670,534)	619,258	-	-	-	(51,276)	19,643,602
14	Additions to Rate Base:									
15	Material and Supplies	271,563				(7,075)			(7,075)	264,488
16	Fuel Stocks	-							-	-
17	Prepayments	76,422				25,865			25,865	102,287
18	Advanced Tax Collection	-				(95,375)			(95,375)	(95,375)
19	Working Capital	-				(390,228)			(390,228)	(390,228)
20	Other	150,700				(9,254)	97,982		88,728	239,428
21	TOTAL ADDITIONS TO RATE BASE	498,685	-	-	-	(476,067)	97,982	-	(378,085)	120,600
22	Deductions to Rate Base:									
23	Accumulated Deferred Income Taxes	1,921,358			21,047				21,047	1,942,405
24	Accumulated Investment Tax Credit	21,525	103,290						103,290	124,815
25	Customer Advances for Construction	57,168				(4,064)			(4,064)	53,104
26	Customer Deposits	159,060							-	159,060
27	Accumulated Provision for Uncollectibles	42,404							-	42,404
28	Accumulated Provision for Injuries and Damages	155,977							-	155,977
29	Miscellaneous Operating Provisions	-							-	-
30	Other	-						205,249	205,249	205,249
31	TOTAL DEDUCTIONS TO RATE BASE	2,357,492	103,290	-	21,047	(4,064)	-	205,249	325,522	2,683,014
32	**TOTAL SOUTH DAKOTA RATE BASE**	**$ 17,836,071**	**(103,290)**	**(670,534)**	**598,211**	**(472,003)**	**97,982**	**(205,249)**	**(754,883)**	**$ 17,081,188**
	Source		KAS-2 Sch 6	KAS-1 Sch 5	KAS-2 Sch 7	DAJ-1, Sch 1,2&3	MMF-1, Sch 4	NG02-011		
	Staff Witness Testimony	Senger	Senger	Senger/Towers	Senger	Jacobson	Michelle	Senger		
	Staff position on MDU's Adjustment	Adjustded	Adjusted	Adjusted	Adjusted	Staff Proposed	Staff Proposed	Staff Proposed		

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2003

Sources

Line 5: Sum of lines 2 through 4
Line 7: Line 5 plus line 6
Line 12: Sum of lines 9 through 11
Line 13: Line 7 less line 12
Line 21: Sum of lines 15 through 20
Line 31: Sum of lines 23 through 30
Line 32: Line 13 plus 21 less line 31

Column b, line 2:	KAS-2, Schedule 4, column q, line 15
Column b, line 3:	KAS-2, Schedule 4, column q, line 39
Column b, line 4:	KAS-2, Schedule 4, column q, line 63
Column b, line 6:	KAS-2, Schedule 3, Page 2 of 4 Column b , line 15
Column b, line 9:	KAS-2, Schedule 5, column o, line 16
Column b, line 10:	KAS-2, Schedule 5, column o, line 40
Column b, line 11:	KAS-2, Schedule 5, column o, line 63
Column b, line 15:	KAS-2, Schedule 3, page 1 of 4 Column b, line 15
Column b, line 16:	Statement M, page 2 of 8
Column b, line 17:	KAS-2, Schedule 3, page 1 of 4 Column c, line 15
Column b, line 18:	N/A
Column b, line 19:	N/A
Column b, line 20:	KAS-2, Schedule 3, page 1 of 4, column d, line 15
Column b, line 23:	KAS-2, Schedule 3, page 2 of 4, Column c, Line 15
Column b, line 24:	KAS-2, Schedule 3, Page 2 of 4, Column d, Line 15
Column b, line 25:	KAS-2, Schedule 3, Page 1 of 4, Column e, line 15
Column b, line 26:	KAS-2, Schedule 3, Page 2 of 3, Column e, line 17
Column b, line 27:	KAS-2, Schedule 3, Page 3 of 4, Column b, line 15
Column b, line 28:	KAS-2, Schedule 3, Page 3 of 4, Column c, line 17
Column b, line 29:	Amount = 0, per DR4-24
Column b, line 30:	N/A
Column c, line 24:	KAS-2, Schedule 6, column d, line 8
Column d, line 9:	KAS-1, Schedule 5, page 1 of 2, column f, line 37
Column d, line 10:	KAS-1, Schedule 5, page 1 of 2, column f, line 38
Column d, line 11:	KAS-1, Schedule 5, page 1 of 2, column f, line 39
Column e, line 2:	KAS-2, Schedule 7, column g, line 17
Column e, line 3:	KAS-2, Schedule 7, column g, line 27
Column e, line 4:	KAS-2, Schedule 7, column g, line 46 plus line 52
Column e, line 9:	KAS-2, Schedule 7, column m, line 17
Column e, line 10:	KAS-2, Schedule 7, column m, line 27
Column e, line 11:	KAS-2, Schedule 7, column m, line 46 plus line 52
Column e, line 23:	KAS-2, Schedule 7, column r, line 54
Column f, line 15:	DAJ-1, Schedule 3, Column d, line 1
Column f, line 17:	DAJ-1, Schedule 3, Column d, line 2
Column f, line 18:	DAJ-1, Schedule 2, Column g, line 4
Column f, line 19:	DAJ-1, Schedule 1, Column b, line 24
Column f, line 20:	DAJ-1, Schedule 3, Column d, line 3
Column f, line 25:	DAJ-1, Schedule 3, Column d, line 4
Column g, line 20:	MMF-1, Schedule 4
Column h, line 30:	NG02-011, settlement, staff memo and exhibits

Column i:	Sum of columns c through l
Column j:	Column b plus column j

Montana-Dakota Utilities Co.
Docket NG04-004
Thirteen point Average Balances
Adjusted Test Year Ending December 31, 2003

Line	MONTH	MATERIAL AND SUPPLIES Ending Balance		PREPAID INSURANCE Ending Balance		UNAMORTIZED FAS 106 Ending Balance		CUSTOMER ADVANCES FOR CONSTRUCTION Ending Balance	
	(a)	(b)		(c)		(d)		(e)	
1	Dec-2002	287,723		17,823		158,631		81,813	
2	Jan-2003	247,598		5,980		157,309		57,488	
3	Mar-2003	235,168		98,307		155,987		57,373	
4	Mar-2003	231,149		86,370		154,666		57,531	
5	Apr-2003	242,360	Source:	138,748	Source:	153,344	Source:	57,738	Source:
6	May-2003	272,287	Statement F	121,737	Statement F	152,022	Statement F	57,896	Statement F
7	Jun-2003	292,817	Sch F-1	113,774	Sch F-1	150,700	Sch F-1	44,711	Sch F-1
8	Jul-2003	289,396	Page 2 of 5	99,687	Page 3 of 5	149,378	Page 4 of 5	45,426	Page 5 of 5
9	Aug-2003	301,084		80,000		148,056		50,590	
10	Sep-2003	290,730		65,923		146,734		51,305	
11	Oct-2003	309,044		59,519		145,412		52,019	
12	Nov-2003	277,306		66,031		144,090		66,077	
13	Dec-2003	253,659		39,592		142,768		63,222	
14	TOTAL	3,530,321		993,491		1,959,097		743,189	
15	AVERAGE	**271,563**	To KAS-2, Sch 2 Col. b, line 15	**76,422**	To KAS-2, Sch 2 Col. b, line 17	**150,700**	To KAS-2, Sch 2 Col. b, line 20	**57,168**	To KAS-2, Sch 2 Col. b, line 25

Montana-Dakota Utilities Co.
Docket NG04-004
Thirteen point Average Balances
Adjusted Test Year Ending December 31, 2003

Line	MONTH	COMPLETED CONSTRUCTION NOT CLASSIFIED Ending Balance		ACCUMULATED DEFERRED INCOME TAXES Ending Balance		ACCUMULATED INVESTMENT TAX CREDIT Ending Balance		CUSTOMER DEPOSITS SD - TOTAL COMPANY Ending Balance	
	(a)	(b)		(c)		(d)		(e)	
1	Dec-2002	718,936		1,734,714		26,861		219,503	
2	Jan-2003	633,069		1,935,623		28,550		218,710	
3	Mar-2003	619,524		1,928,704		27,368		217,373	
4	Mar-2003	600,548		1,921,786		26,186		216,252	
5	Apr-2003	368,502	**Source:**	1,970,216	**Source:**	25,004	**Source:**	213,314	**Source:**
6	May-2003	417,910	Company	1,977,135	Company	23,821	Company	207,776	Company
7	Jun-2003	579,693	Response to	1,984,054	Response to	22,639	Response to	208,341	Response to
8	Jul-2003	258,946	DR2-18, DR3-1	1,742,609	DR1-14	21,457	DR1-15	206,136	DR1-16
9	Aug-2003	307,372	and 9/30/04	1,964,343		18,159		203,430	
10	Sep-2003	317,737	email from	1,967,567		16,827		211,201	
11	Oct-2003	244,269	Rita Mulkern	1,970,790		15,495		223,053	
12	Nov-2003	407,971		1,974,013		14,163		229,661	
13	Dec-2003	324,862		1,906,097		13,297		232,485	
14	TOTAL	5,799,339		24,977,651		279,827		2,807,235	
15	AVERAGE	**446,103**	**To**	**1,921,358**	**To**	**21,525**	**To**	215,941	
			KAS-2, Sch 2		KAS-2, Sch 2		KAS-2, Sch 2		
16			Col. b, line 6		Col. b, line 23		Col. b, line 24	73.6590%	Allocation BH gas rev alloc
17								**159,060**	**To** KAS-2, Sch 2 Col. b, line 26

Montana-Dakota Utilities Co.
Docket NG04-004
Thirteen point Average Balances
Adjusted Test Year Ending December 31, 2003

Line	MONTH	ACCUMULATED PROVISION FOR UNCOLLECTIBLES Ending Balance		TOTAL UTILITY ACCUMULATED PROVISION FOR INJURIES & DAMAGES Ending Balance		Ending Balance		Ending Balance	
	(a)	(b)		(c)		(d)		(e)	
1	Dec-2002	27,919		1,415,463					
2	Jan-2003	47,213		1,388,363					
3	Mar-2003	55,405		1,370,946					
4	Mar-2003	65,937		1,617,096					
5	Apr-2003	65,333	Source:	1,574,548	Source:		Source:		Source:
6	May-2003	56,862	Company	1,553,591	Company				
7	Jun-2003	47,076	Response to	1,546,611	Response to				
8	Jul-2003	41,220	DR1-17	1,372,768	DR1-19				
9	Aug-2003	32,560		1,308,918					
10	Sep-2003	22,084		1,260,555					
11	Oct-2003	19,612		1,243,529					
12	Nov-2003	27,302		1,040,721					
13	Dec-2003	42,726		1,017,175					
14	TOTAL	551,249		17,710,284		-		-	
15	AVERAGE	**42,404**	To KAS-2, Sch 2 Col. b, line 27	1,362,330		-	To	-	To
16				11.4493%	Allocation BH gas rev alloc				
17				**155,977**	To KAS-2, Sch 2 Col. b, line 28				

Montana-Dakota Utilities Co.
Docket NG04-004
Thirteen Point Average Balances
Adjusted Test Year Ending December 31, 2003

	Electric		Gas		
	Total Company Sales Revenues	**South Dakota Sales Revenues**	**Total Company Sales & Transport Revenues**	**SD-Black Hills Sales & Transport Revenues**	**SD-East River Sales & Transport Revenues**
1/1/03 to 12/31/03 (December 2003 YTD)	146,756,263	10,353,266	231,014,690	43,252,101	5,113,997

SD Black Hills Gas as % of Total SD Utility (SD gas and electric) **73.6590%**

SD Black Hills gas as percent of Total Utility (all gas and electric) **11.4493%**

SOURCE: MDU Monthly reports - excluding "Other Operating Revenue"

Montana-Dakota Utilities Co.
Docket NG04-004
Plant in Service - 13 point Average Balances
Adjusted Test Year Ending December 31, 2003

MONTANA-DAKOTA UTILITIES CO.
GAS PLANT IN SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE THIRTEEN MONTHS ENDED DECEMBER 31, 2003

	Acct. No.	Account	12/31/02	1/31/2003	2/28/2003	3/31/2003	4/30/2003	5/31/2003	6/30/2003	7/31/2003	8/31/2003	9/30/2003	10/31/2003	11/30/2003	12/31/2003	(Staff Calcualted) 13 Point Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1		Distribution Plant														
2	374.1	Land	30,306	30,306	30,306	30,306	30,306	30,306	30,306	29,922	29,922	29,922	29,922	29,922	29,922	30,129
3	374.2	Rights of Way	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609
4	375	Structures & Improvements	37,325	37,325	37,325	37,325	37,325	37,325	37,325	37,325	39,112	39,785	39,785	39,785	39,785	38,219
5	376	Mains	17,929,972	18,086,929	18,212,814	18,241,616	18,260,945	18,289,143	18,301,359	18,778,895	18,808,625	18,938,040	18,924,112	18,921,364	19,047,110	18,518,533
6	378	Meas & Reg Equip-General	243,979	243,979	243,979	243,979	243,979	252,541	252,541	252,541	256,253	257,697	257,697	257,697	258,883	251,211
7	379	Meas & Reg Equip-City Gate	58,623	58,623	58,623	58,623	58,623	58,623	58,623	77,548	78,548	78,548	78,548	78,548	78,548	67,742
8	380	Services	5,377,654	5,423,322	5,429,370	5,462,742	5,475,730	5,487,669	5,503,739	5,548,253	5,571,703	5,639,812	5,631,965	5,631,965	5,738,455	5,532,491
9	381	Positive Meters	5,998,919	6,059,207	6,063,743	6,088,359	6,117,210	6,130,333	6,173,742	6,200,818	6,216,017	6,287,434	6,287,434	6,300,505	6,327,447	6,173,167
10	383	Service Regulators	840,674	850,631	858,056	856,925	858,770	861,542	864,284	868,124	872,573	878,458	878,458	882,845	884,630	865,844
11	385	Ind Meas & Reg Sta Eqpt	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429	63,429
12	386	Other Property on Cust. Premise	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931	170,931
13	387.1	Cathodic Protection Equip.	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245	66,245
14	387.2	Other Distribution Equip.	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342	86,342
15		**Total Distribution Plant**	**30,913,008**	**31,185,878**	**31,329,772**	**31,415,431**	**31,478,444**	**31,543,038**	**31,617,475**	**32,188,982**	**32,268,309**	**32,545,252**	**32,523,477**	**32,538,187**	**32,800,336**	**31,872,892**
16		General Plant														
17	389	Land	582,013	581,076	581,076	580,983	580,983	580,983	580,983	580,983	580,983	580,983	580,983	580,983	580,983	581,077
18	390	Structures and Improvements	3,775,980	3,770,417	3,770,417	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,769,782	3,770,356
19	391.1	Furniture & Fixtures	364,448	317,021	317,021	317,270	317,270	317,270	317,270	317,270	317,270	226,766	226,766	226,766	226,766	293,013
20	391.3	Computer Equip.-PC	237,293	214,285	214,285	216,295	225,003	227,199	226,161	226,161	231,526	255,293	255,293	255,293	255,293	233,798
21	392.1	Transportation Equip, Non-Un.	35,860	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859	35,859
22	392.2	Transportation Equip, Unitized	1,910,571	1,800,394	1,821,078	1,821,441	1,820,646	1,785,735	1,769,285	1,727,579	1,676,878	1,676,878	1,654,348	1,654,348	1,849,562	1,766,826
23	393	Stores Equipment	56,721	56,721	56,721	56,721	56,721	56,721	56,721	56,721	56,721	45,724	45,724	45,724	45,724	53,337
24	394.1	Tools,Shop&Gar. Equip.-Non-Un.	520,410	524,050	524,050	524,050	524,050	524,050	549,223	549,223	549,223	337,075	342,376	342,376	346,507	473,589
25	394.2	Tools,Shop&Gar. Equip.-Unitized	57,875	57,875	57,875	57,875	57,875	57,875	57,875	57,875	57,875	24,072	24,072	24,072	24,072	47,474
26	394.3	Vehicle Maintenance Equip.	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627	7,627
27	394.4	Vehicle Refueling Equip.	138,079	138,079	138,079	138,079	138,079	138,079	138,079	138,079	138,079	66,386	66,386	66,386	66,386	116,020
28	395	Laboratory Equipment	42,947	42,995	42,995	42,995	42,995	42,995	42,995	42,995	42,995	19,588	19,588	19,588	19,588	35,789
29	396.1	Work Equipment Trailers	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572	96,572
30	396.2	Power Operated Equip.	1,184,412	1,167,431	1,196,898	1,196,898	1,185,013	1,235,097	1,482,734	1,486,988	1,486,988	1,571,351	1,529,184	1,529,184	1,540,151	1,368,641
31	397.1	Radio Comm. Equip.-Fixed	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627	97,627
32	397.2	Radio Comm. Equip.-Mobile	125,394	125,394	125,394	126,103	126,620	126,620	126,620	126,620	126,620	126,620	126,620	126,620	126,620	126,297
33	397.3	General Tele. Comm. Equip.	47,773	47,773	47,773	47,773	47,773	47,773	47,773	47,773	47,773	25,321	25,321	25,321	25,321	40,865
34	397.5	Supervisory & Tele. Equip.	84,779	84,878	84,878	84,878	84,878	84,878	84,878	84,878	84,878	0	0	0	0	58,754
35	397.6	Scada System	770	770	770	770	770	770	770	770	770	0	0	0	0	533
36	397.8	Network Equipment	18,671	18,671	22,356	22,356	22,356	22,356	22,356	22,356	22,356	23,831	23,831	23,831	23,831	22,243
37	398	Miscellaneous Equipment	33,279	33,349	33,349	33,349	33,349	33,349	33,349	33,349	33,349	9,069	9,069	9,069	9,611	25,915
38	303	Intangible Plant - General	135,079	138,705	138,705	138,705	138,705	138,705	138,705	138,705	138,705	138,705	138,705	138,705	138,705	138,426
39		**Total General Plant**including Intangible	**9,554,180**	**9,357,569**	**9,411,405**	**9,414,008**	**9,410,553**	**9,427,922**	**9,683,244**	**9,645,792**	**9,600,456**	**9,135,129**	**9,075,733**	**9,075,733**	**9,286,587**	**9,390,638**
40		Common Plant														
41	389	Land	31,426	35,977	35,977	35,977	35,977	35,977	35,977	35,977	35,977	35,977	35,977	35,977	35,977	35,627
42	390	Structures and Improvements	390,451	447,346	447,346	447,346	447,346	447,346	447,346	447,346	447,346	451,366	451,366	451,358	462,432	445,057
43	391.1	Furniture & Fixtures	160,910	184,754	185,429	184,690	184,820	184,797	184,026	184,026	184,784	122,092	122,092	122,092	123,640	163,704
44	391.2	Computer Equipment-Bull/AS400	6,671	7,646	7,646	7,646	7,646	7,646	7,646	7,646	7,646	1,218	1,218	1,218	1,218	5,593
45	391.3	Computer Equip.-PC	226,938	233,845	234,322	236,158	241,622	242,572	244,600	244,600	247,099	238,456	238,456	238,456	242,574	239,208
46	391.4	Computer Equip. - Other (EMS)	388	450	450	450	450	450	450	450	450	450	450	450	450	445
47	391.5	Computer Equip.-Other	58,283	66,802	66,802	66,802	66,802	66,802	66,988	66,988	66,988	4,522	4,522	4,522	5,312	47,087
48	392.1	Trans. Equip., Non-Unitized	1,639	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,870	1,852
49	392.2	Trans. Equip., Unitized	56,235	64,833	61,880	64,683	63,972	62,516	55,277	55,277	57,996	58,589	58,589	56,282	55,331	59,343
50	392.3	Aircraft	77,196	88,480	356,645	356,645	356,645	370,888	370,888	370,888	370,888	377,806	377,806	377,806	377,806	325,414
51	393	Stores Equip.	283	323	323	323	323	323	323	323	323	323	323	323	323	320
52	394.1	Tools, Shop and Garage Equip.	1,993	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,285	2,263
53	394.3	Vehicle Maint. Equip.	6,103	6,960	6,960	7,153	7,153	7,153	7,153	7,153	7,850	7,850	7,850	7,850	7,850	7,311
54	394.4	Vehicle Refueling Equip.	6,848	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,388	8,270
55	396.2	Work Equipment Trailers	3,697	4,217	4,217	4,217	4,217	4,217	4,217	4,217	0	0	0	0	0	2,555
56	397.1	Radio Comm. Equip.-Fixed	13,559	15,541	15,541	15,541	15,541	15,541	15,541	15,541	15,541	10,645	10,645	10,645	10,645	13,882
57	397.2	Radio Comm. Equip.-Mobile	18,072	20,714	20,714	20,714	20,714	21,960	21,960	21,960	21,960	21,960	21,960	21,960	21,960	21,278
58	397.3	General Tele. Comm. Equip.	28,933	32,920	32,920	32,920	32,743	33,093	34,372	34,372	35,959	32,733	32,733	32,733	32,994	33,033
59	397.5	Supervisory & Tele. Equip.	156	179	179	179	179	179	179	179	179	179	179	179	179	177
60	397.8	Network Equipment	66,646	76,481	76,322	76,654	78,386	78,526	33,190	33,190	33,190	27,537	27,537	27,537	28,388	51,045
61	398	Miscellaneous Equipment	31,229	35,790	35,790	35,790	35,790	35,790	35,790	35,790	35,870	34,704	34,704	34,704	35,405	35,165
62	303	Intangible Plant - Common	1,073,230	1,226,125	1,229,334	1,229,334	1,229,334	1,229,331	1,229,331	1,229,331	1,229,331	1,240,768	1,240,768	1,240,768	1,240,928	1,232,872
63		**Total Common Plant**	**2,260,886**	**2,561,926**	**2,831,340**	**2,835,765**	**2,842,203**	**2,857,650**	**2,807,797**	**2,807,797**	**2,811,920**	**2,679,718**	**2,679,718**	**2,677,403**	**2,695,955**	**2,731,501**
64		**Total Gas Plant in Service**	**42,728,074**	**43,105,373**	**43,572,517**	**43,665,204**	**43,731,200**	**43,828,610**	**44,108,516**	**44,642,571**	**44,680,685**	**44,360,099**	**44,278,928**	**44,291,323**	**44,782,878**	**43,995,031**

sources:
Columns a through o: MDU response 188, Attachment A
Column q: Sum of column c throuhg o divided by 13

Montana-Dakota Utilities Co.
Docket NG04-004
Accumulated Depreciation - 13 point Average Balances
Adjusted Test Year Ending December 31, 2003

Montana-Dakota Utilities Co.
Accumulated Reserve for Depreciation/Amortization
Gas Utility - South Dakota
For the Thirteen Months Ended December 31, 2003

	Account No. & Description	12/31/02	1/31/2003	2/28/2003	3/31/2003	4/30/2003	5/31/2003	6/30/2003	7/31/2003	8/31/2003	9/30/2003	10/31/2003	11/30/2003	12/31/2003	(Staff Calcualted) 13 Point Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	Distribution Plant														
2	3741 Land-Gas Dis	0	0	0	0	0	0	(1,170)	0	0	0	0	0	0	(90)
3	3742 Rights of Way-Gas Dis	(5,069)	(5,087)	(5,106)	(5,124)	(5,143)	(5,161)	(5,180)	(5,198)	(5,217)	(5,235)	(5,254)	(5,272)	(5,291)	(5,180)
4	375 Structures&Improve-Ga	(10,420)	(10,495)	(10,569)	(10,644)	(10,718)	(10,793)	(10,868)	(10,942)	(11,017)	(11,095)	(11,175)	(11,254)	(11,334)	(10,871)
5	376 Mains	(12,762,392)	(12,820,935)	(12,859,715)	(12,918,113)	(12,973,330)	(13,021,747)	(13,068,616)	(13,135,367)	(13,196,730)	(13,257,682)	(13,308,114)	(13,369,474)	(13,430,425)	(13,086,355)
6	378 Meas & Reg Equip-General	(108,125)	(108,593)	(109,060)	(109,528)	(109,996)	(109,082)	(109,566)	(110,050)	(110,322)	(110,813)	(111,307)	(111,801)	(112,295)	(110,041)
7	379 Meas & Reg Equip-City Gate	(37,079)	(37,212)	(37,346)	(37,480)	(37,614)	(37,748)	(37,882)	(36,976)	(37,153)	(37,333)	(37,512)	(37,691)	(37,871)	(37,454)
8	380 Services - Gas	(5,117,369)	(5,144,619)	(5,178,288)	(5,212,308)	(5,249,639)	(5,281,870)	(5,319,336)	(5,341,300)	(5,379,306)	(5,417,472)	(5,445,018)	(5,483,597)	(5,522,176)	(5,314,792)
9	381 Positive Meters	(2,227,796)	(2,260,303)	(2,273,332)	(2,284,486)	(2,297,641)	(2,310,825)	(2,325,225)	(2,338,490)	(2,351,912)	(2,365,277)	(2,380,557)	(2,394,075)	(2,407,795)	(2,324,440)
10	383 Service Regulators	(336,351)	(340,708)	(342,370)	(342,352)	(344,079)	(345,788)	(347,496)	(348,898)	(350,588)	(352,459)	(354,603)	(356,338)	(358,097)	(347,702)
11	385 Industrial Measur&Reg	(20,709)	(20,810)	(20,911)	(21,012)	(21,113)	(21,214)	(21,315)	(21,416)	(21,517)	(21,618)	(21,719)	(21,820)	(21,921)	(21,315)
12	3862 Other Property on Cust.Premise	(137,290)	(138,621)	(139,953)	(141,285)	(142,617)	(143,949)	(145,281)	(146,612)	(147,944)	(149,276)	(150,608)	(151,940)	(153,272)	(145,281)
13	3863 CNG Leases	91	91	91	91	91	91	91	91	91	91	91	91	91	91
14	3871 Cathodic Protection E	(33,482)	(33,770)	(34,057)	(34,345)	(34,633)	(34,920)	(35,208)	(35,495)	(35,783)	(36,071)	(36,358)	(36,646)	(36,934)	(35,208)
15	3872 Other Distribution Eq	(53,020)	(53,395)	(53,769)	(54,144)	(54,519)	(54,894)	(55,269)	(55,644)	(56,019)	(56,394)	(56,769)	(57,144)	(57,519)	(55,269)
16	**Total Distribution Plant**	(20,849,011)	(20,974,457)	(21,064,385)	(21,170,730)	(21,280,951)	(21,377,900)	(21,482,321)	(21,586,297)	(21,703,417)	(21,820,614)	(21,918,903)	(22,036,961)	(22,154,839)	(21,493,907)
17	General Plant														
18	390 Structures&Improvemen	(108,648)	(116,138)	(123,490)	(132,085)	(139,436)	(146,787)	(154,138)	(161,489)	(168,840)	(176,191)	(183,542)	(190,893)	(198,245)	(153,840)
19	3911 Office Furniture & Eq	(115,386)	(60,866)	(61,936)	(63,006)	(64,076)	(65,147)	(66,218)	(67,289)	(68,360)	20,154	18,163	16,173	14,182	(43,355)
20	3912 Computer Equip.-Honey	(905)	(904)	(904)	(904)	(904)	(904)	(904)	(904)	(904)	(904)	(904)	(904)	(904)	(904)
21	3913 Computer Equip.-PC	(93,441)	(72,971)	(75,203)	(77,435)	(79,668)	(82,032)	(84,399)	(86,754)	(89,110)	(88,270)	(90,930)	(93,589)	(96,266)	(85,391)
22	3921 Transportation Equip,	(27,594)	(27,766)	(27,938)	(28,109)	(28,281)	(28,452)	(28,624)	(28,795)	(28,967)	(29,138)	(29,310)	(29,481)	(29,653)	(28,624)
23	3922 Transportation Equip,	(570,016)	(472,694)	(468,239)	(476,950)	(492,767)	(466,567)	(474,297)	(441,053)	(404,516)	(415,537)	(402,457)	(410,371)	(407,437)	(454,069)
24	393 Stores Equipment	(13,848)	(13,891)	(13,933)	(13,976)	(14,019)	(14,061)	(14,104)	(14,146)	(14,189)	(3,333)	(3,473)	(3,614)	(3,755)	(10,796)
25	3941 Tools,Shop&Gar.Equip.-Non-Un.	(215,700)	(217,287)	(218,846)	(220,405)	(221,964)	(223,523)	(225,082)	(226,716)	(228,350)	(10,782)	(14,016)	(17,274)	(20,532)	(158,498)
26	3942 Tools,Shop&Gar.Equip.-Unitized	(53,354)	(53,354)	(53,354)	(53,354)	(53,354)	(53,354)	(53,354)	(53,354)	(53,354)	(15,514)	(15,646)	(15,646)	(15,646)	(41,741)
27	3943 Vehicle Maintenance E	(2,798)	(2,825)	(2,852)	(2,878)	(2,905)	(2,932)	(2,959)	(2,986)	(3,012)	(3,049)	(3,086)	(3,122)	(3,159)	(2,966)
28	3944 Vehicle Refueling Equ	(111,741)	(112,817)	(113,892)	(114,968)	(116,044)	(117,120)	(118,196)	(119,272)	(120,348)	(49,145)	(49,634)	(50,124)	(50,614)	(95,686)
29	395 Laboratory Equipment	(5,011)	(5,103)	(5,186)	(5,269)	(5,352)	(5,435)	(5,518)	(5,602)	(5,685)	17,509	17,127	16,914	16,701	1,545
30	3961 Work Equipment Traile	(16,660)	(17,048)	(17,437)	(17,826)	(18,215)	(18,603)	(18,992)	(19,381)	(19,769)	(20,158)	(20,547)	(20,935)	(21,324)	(18,992)
31	3962 Power Operated Equipm	(970,069)	(975,102)	(998,634)	(1,053,534)	(729,838)	(734,691)	(551,212)	(540,723)	(546,708)	(552,694)	(511,324)	(517,479)	(523,634)	(708,126)
32	3971 Fixed Radio Communica	(50,180)	(50,479)	(50,778)	(51,076)	(51,375)	(51,673)	(51,972)	(52,271)	(52,569)	(53,162)	(53,755)	(54,348)	(54,942)	(52,198)
33	3972 Mobile Radio Communic	(56,717)	(57,100)	(57,484)	(57,867)	(58,253)	(58,640)	(59,027)	(59,415)	(59,802)	(58,845)	(59,521)	(60,197)	(60,873)	(58,749)
34	3973 General Telephone Com	(9,847)	(10,108)	(10,369)	(10,630)	(10,891)	(11,152)	(11,414)	(11,675)	(11,936)	10,095	9,674	9,253	8,832	(4,628)
35	3975 Supervisory&Telemeter	(84,779)	(84,868)	(84,868)	(84,868)	(84,868)	(84,868)	(84,868)	(84,868)	(84,868)	10	10	10	10	(58,745)
36	3976 Scada System	(770)	(770)	(770)	(770)	(770)	(770)	(770)	(770)	(770)	-	-	-	-	(533)
37	3978 Network Equipment	(8,310)	(8,504)	(8,428)	(8,661)	(8,894)	(9,127)	(9,359)	(9,592)	(9,825)	(10,293)	(10,786)	(11,279)	(11,772)	(9,602)
38	3980 Miscellaneous Equipme	(16,318)	(16,376)	(16,393)	(16,409)	(16,426)	(16,442)	(16,458)	(16,475)	(16,491)	7,700	7,611	7,523	7,435	(9,040)
39	303 Misc. Intangible Plant-General	(131,474)	(135,065)	(135,159)	(135,252)	(135,346)	(135,439)	(135,533)	(135,626)	(135,720)	(135,813)	(135,907)	(136,000)	(136,094)	(135,264)
40	**Total General Plant Including Intangible**	(2,663,566)	(2,512,036)	(2,546,093)	(2,626,232)	(2,333,666)	(2,327,719)	(2,167,398)	(2,139,156)	(2,124,093)	(1,567,360)	(1,532,253)	(1,565,383)	(1,587,690)	(2,130,202)
41	Common Plant														
42	390 Structures&Improvemen	(167,113)	(192,849)	(194,251)	(195,653)	(197,054)	(198,456)	(199,858)	(201,260)	(202,661)	(204,088)	(205,502)	(206,917)	(207,843)	(197,962)
43	3911 Office Furniture & Eq	(70,206)	(80,470)	(80,702)	(80,096)	(78,498)	(78,615)	(77,786)	(78,035)	(77,731)	(10,010)	(10,923)	(11,838)	(12,750)	(57,512)
44	3912 Computer Equip./AS400	(4,938)	(5,660)	(5,660)	(5,660)	(5,660)	(5,660)	(5,660)	(5,660)	(5,660)	768	768	768	768	(3,627)
45	3913 Computer Equip.-PC	(88,393)	(77,323)	(79,760)	(82,202)	(84,790)	(87,307)	(89,826)	(92,375)	(94,921)	(86,197)	(88,683)	(91,166)	(93,650)	(87,430)
46	3914 Computer Equip.-EMS	(402)	(461)	(461)	(461)	(461)	(461)	(461)	(461)	(461)	(461)	(461)	(461)	(461)	(456)
47	3915 Computer Equip.-Other	(58,341)	(66,868)	(66,868)	(66,868)	(66,868)	(66,868)	(66,868)	(66,868)	(66,868)	(4,156)	(4,103)	(4,111)	(4,118)	(46,906)
48	3921 Trans. Equip., Non-Unitized	(2,969)	(3,178)	(3,187)	(3,187)	(3,187)	(3,187)	(3,187)	(3,187)	(3,187)	(3,187)	(3,187)	(3,187)	(3,187)	(3,171)
49	3922 Trans. Equip., Unitized	(17,857)	(19,458)	(19,324)	(19,841)	(20,154)	(17,133)	(15,525)	(15,789)	(16,187)	(15,132)	(15,765)	(13,739)	(13,909)	(16,909)
50	3923 Aircraft	(23,931)	(98,863)	-	(1,976)	(3,255)	(4,133)	(5,725)	(6,932)	(8,107)	(9,444)	(10,472)	(11,530)	(12,930)	(15,177)
51	393 Stores Equipment	(62)	(71)	(72)	(73)	(74)	(75)	(76)	(77)	(78)	(78)	(79)	(80)	(81)	(75)
52	3941 Miscellaneous Tools,	(344)	(400)	(407)	(413)	(420)	(427)	(433)	(440)	(446)	(458)	(469)	(481)	(493)	(433)
53	3943 Vehicle Maintenance E	(2,834)	(3,258)	(3,284)	(3,309)	(3,336)	(3,363)	(3,389)	(3,416)	(3,442)	(3,474)	(3,505)	(3,536)	(3,567)	(3,363)
54	3944 Vehicle Refueling Equ	(4,393)	(5,520)	(5,578)	(5,637)	(5,696)	(5,755)	(5,814)	(5,873)	(5,932)	(5,962)	(5,993)	(6,023)	(6,054)	(5,710)
55	3962 Power Operated Equipm	(2,013)	(2,313)	(2,330)	(2,347)	(2,364)	(2,381)	(2,398)	(2,415)	-	-	-	-	-	(1,428)
56	3971 Fixed Radio Communica	(7,438)	(8,581)	(8,637)	(8,693)	(8,749)	(8,806)	(8,862)	(8,918)	(8,974)	(4,153)	(4,230)	(4,306)	(4,382)	(7,287)
57	3972 Mobile Radio Communic	(2,918)	(3,459)	(3,575)	(3,690)	(3,805)	(3,920)	(4,043)	(4,165)	(4,287)	(4,399)	(14,448)	(14,559)	(14,671)	(6,303)
58	3973 General Telephone Com	(17,352)	(19,969)	(20,261)	(20,552)	(20,666)	(20,956)	(21,248)	(21,553)	(21,857)	(18,403)	(17,279)	(17,546)	(17,813)	(19,650)
59	3975 Supervisory&Telemeter	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
60	3978 Network Equipment	(28,846)	(33,856)	(34,590)	(35,385)	(36,184)	(37,000)	(16,789)	(17,135)	(17,481)	(10,714)	(11,170)	(11,609)	(12,047)	(23,293)
61	398 Miscellaneous Equipme	(15,569)	(17,917)	(17,992)	(18,067)	(18,142)	(18,216)	(18,291)	(18,366)	(18,441)	(17,035)	(17,119)	(17,204)	(17,288)	(17,665)
62	303 Misc. Intangible Plant	(482,674)	(562,733)	(573,094)	(583,163)	(593,206)	(603,249)	(613,292)	(623,335)	(633,378)	(643,420)	(653,424)	(663,214)	(673,004)	(607,784)
63	**Total Common Plant Including Intangible**	(998,617)	(1,203,212)	(1,120,038)	(1,137,278)	(1,152,575)	(1,165,974)	(1,159,537)	(1,176,266)	(1,190,104)	(1,040,009)	(1,068,051)	(1,080,745)	(1,097,487)	(1,122,147)
64	**Total Gas Plant In Service**	(24,511,194)	(24,689,706)	(24,730,515)	(24,934,241)	(24,767,192)	(24,871,594)	(24,809,256)	(24,901,719)	(25,017,614)	(24,427,983)	(24,517,206)	(24,683,088)	(24,840,015)	(24,746,256)

Sources:
Column a through n: MDU Response 1-12, Attachment A
Column o: Sum of columns b through n divided by 13

Montana-Dakota Utilities Co.
Docket NG04-004
Accumulated Deferred Investment Tax Credit
Adjusted Test Year Ending December 31, 2003

Line	(a)	Gas Plant (b)	Common Plant (c)	TOTAL (d)	
1	Unamortized ITC - 26.0 yr. Life Balance at 12/31/2002	534,415	113,936		
2	Unamortized ITC - 26.0 yr. Life Balance at 12/31/2002	406,488	86,170		
	Average Balance	470,452	100,053		
2	SD Gross Plant - Juris. No. 223	22.328275%			
3	Common Split - Gas - Utility No. 26		36.794625%		
4	Allocation subtotal		41,922		
5	SD Common Plant - Juris. No. 221		13.092772%		
6	South Dakota Allocation	119,326	5,489	$ 124,815	
7	Staff per books ITC			21,525	
8	Difference (Staff adjustment to per books)			**103,290**	To KAS-2 Sch 2 col c Line 24

SOURCES:
Lines 1 - 3, 5: Company response to DR3-1
Line 7: KAS-2, Schedule 2, column b, line 24

Montana-Dakota Utilities Co.
Docket NG04-004
Plant Additions/Depreciation/Accum. Depr.
Adjusted Test Year Ending December 31, 2003

MONTANA-DAKOTA UTILITIES CO.
PLANT ADDITIONS - SUMMARY
GAS UTILITY - SOUTH DAKOTA
PRO FORMA 2004
Response to DR1-10

STAFF ADJUSTMENT
PLANT ADDITIONS

	Project No. (a)	Acct. No (b)	Description (c)	Projected Expenditures (d)	Actual Expenditures Thru 7/31/04 (e)	Revenue/ Non-Revenue/ Replacement (f)	Staff Accepted Plant Additions (acutal) (g)	Staff Proposed Depr. Rates (h)	Notes (i)	Annual Depr. Exp. To Depr. Expense (new rates) (j)	Annual Depr. Exp. To Clearing Accounts (new rates) (k)	Annual Accumulated Depreciation (new rates) (l)	Average Annual Accumulated Depreciation (new rates) (m)	2003 Percent of Clearing Acct. Depr. To O&M (new rates) (n)	Plant Addition Depr. Exp. To O&M (new rates) (col k * col n) (o)	Tax Depreciation Rate (p)	Tax Depreciation Amount (q)	Excess Tax/Book Depr. (r)
			Distribution															
1	~~B13430G~~	~~376~~	~~Mains - Black Hills - Growth~~	~~$682,320~~	~~$376,811~~	~~Revenue~~												
2	B13430R	376	Mains - Black Hills - Replacement	223,329	92,339	Non-Rev/Replace	92,339	1.92%		1,773		1,773	887					
3	J131204	376	Relocate Main on Omaha St.	12,143	12,143	Non-Rev/Replace	12,143	1.92%		233		233	117					
4	J144199	376	Relocate 8" and 4" Gas Main	39,600		Non-Rev/Replace												
5	J144208	376	Relocate 4" Gas Main 79th Street	28,431		Non-Revenue												
6	~~J148522~~	~~376~~	~~Install Main-Elk Vale Road Project~~	~~450,643~~	~~28,758~~	~~Revenue~~												
7	~~J149302~~	~~376~~	~~Install 4" Gas Main-Elk Vale Road Project~~	~~66,995~~	~~255~~	~~Revenue~~												
8	~~B13434~~	~~378~~	~~Measuring & Regulators~~	~~22,540~~	~~14,167~~	~~1/~~												
9	B900034	378	Measuring & Regulating Equipment	1,073		Non-Revenue												
10	~~J149325~~	~~378~~	~~Regulator Station-Elk Vale Road Road Project~~	~~24,686~~	-	~~Revenue~~												
11	~~J149326~~	~~378~~	~~Regulator Station-Homestead and Elk Vale~~	~~17,002~~	-	~~Revenue~~												
12	~~B13433~~	~~380~~	~~Service Lines~~	~~241,031~~	~~278,657~~	~~1/~~												
13	~~B90031~~	~~381~~	~~Meters~~	~~218,465~~	~~129,786~~	~~1/~~												
14	J144408	381	Install Gas Meter Reading ERTs	22,799		Non-Revenue												
15	~~B90032~~	~~383~~	~~Regulators~~	~~35,607~~	~~13,479~~	~~1/~~												
16	B13435	387.1	Cathodic Protection	15,010		Non-Revenue												
17			TOTAL DISTRIBUTION	2,101,874	946,395		104,482	To KAS-2, Sch 2 col e, line 3		2,006	0	2,006	1,004	To KAS-2, Sch 2 col e, line 9	0	3.750%	3,918	1,912
18			General															
19	B13442	391.1	Office Equipment	6,234	3,056	Non-Revenue	3,056	4.97%		152		152	76			14.286%	437	285
20	B13440	391.3	Personal Computers	1,541		Non-Revenue										20.000%	-	-
21	B13438	392.2	Vehicles	288,794	150,795	Non-Revenue	150,795	21.13%	C/A		31,863	31,863	15,932	82.56%	26,306	20.000%	30,159	(1,704)
22	B13443	394.1	Minor Work Equipment	20,771	10,208	Non-Revenue	10,208	6.62%		676		676	338			14.286%	1,458	782
23	B90043	394.1	Minor Work Equipment	980	106	Non-Revenue	106	6.62%		7		7	4			14.286%	15	8
24	J148672	394.1	Purchase Electrofusion Equipment	12,287	13,085	Non-Revenue	13,085	6.62%		866		866	433			14.286%	1,869	1,003
25	B13439	396.2	Work Equipment	174,319	109,919	Non-Revenue	109,919	0.00%	C/A		-	-	-	16.44%	-	14.286%	15,703	15,703
26	B13444	397.1	Communication Equipment	15,579		Non-Revenue										14.286%	-	-
27			TOTAL GENERAL	520,505	287,169		287,169	To KAS-2, Sch 2 col e, line 4		1,701	31,863	33,564	16,783	To KAS-2, Sch 2 col e, line 10	26,306		49,641	16,077
28			Common															
29	J144913	390	Install Multi-Stack Modular Chiller	12,442	13,839	Non-Revenue	13,839	2.93%		405		405	203			14.286%	1,977	1,572
30	J148319	390	Replace Lighting-Annex Building 3rd Floor	2,035	2,231	Non-Revenue	2,231	2.93%		65		65	33			14.286%	319	254
31	B90082	391.1	Office Equipment	11,399	4,847	Non-Revenue	4,847	4.95%		240		240	120			14.286%	692	452
32	J144173	391.1	Purchase 4 Workstations	1,105		Non-Revenue										14.286%	-	-
33	J148516	391.1	Purchase 3 Context Workstations	1,450	1,450	Non-Revenue	1,450	4.95%		72		72	36			14.286%	207	135
34	J148712	391.1	Purchase Overhead Storage Unit	242	242	Non-Revenue	242	4.95%		12		12	6			14.286%	35	23
35	J149541	391.1	Purchase Chair	49	49	Non-Revenue	49	4.95%		2		2	1			14.286%	7	5
36	B90080	391.3	Personal Computers	40,865	26,460	Non-Revenue	26,460	23.29%		6,163		6,163	3,082			14.286%	3,780	(2,383)
37	J133994	391.3	Purchase Imaging System	14,414	12,498	Non-Revenue	12,498	23.29%		2,911		2,911	1,456			14.286%	1,785	(1,126)
38	J149507	391.3	30 Walkabout MDTs for Mobile Up	14,265	118	Non-Revenue	118	23.29%		27		27	14			14.286%	17	(10)
39	J120082	391.5	Bar Coding Equipment - Mobile Up	3,827		Non-Revenue										14.286%	-	-
40	B90078	392.2	Vehicles	15,397	13,125	Non-Revenue	13,125	13.33%	C/A		1,750	1,750	875	82.56%	1,445	14.286%	1,875	125
41	B90083	394.1	Minor Work Equipment	277	277	Non-Revenue	277	6.11%		17		17	9			14.286%	40	23
42	B90084	397.1	Communication Equipment	5,952	134	Non-Revenue	134	4.99%		7		7	4			14.286%	19	12
43	B90081	397.8	Network Equipment	6,378	3,703	Non-Revenue	3,703	17.95%		665		665	333			14.286%	529	(136)
44	J148765	398	Replace UPS Batteries	737	886	Non-Revenue	886	2.41%		21		21	11			14.286%	127	106
45	J149141	398	Purchase Electric Punch	84	84	Non-Revenue	84	2.41%		2		2	1			14.286%	12	10
46			TOTAL COMMON	130,918	79,943		79,943	To KAS-2, Sch 2 col e, line 5		10,609	1,750	12,359	6,184	To KAS-2, Sch 2 col e, line 11	1,445		11,421	(938)
47			Common Intangible															
48	J144387	303	Upgrade MUP to Version 6	22,109	108	Non-Revenue	108	9.41%		10		10	5					
49	J144635	303	Upgrade Financial Forecast System	42,677	91,107	Non-Revenue	91,107	9.41%		8,573		8,573	4,287					
50	J144879	303	Implement JDE One World	45,067		Non-Revenue						-	-					
51	J61813	303	Develop GEMS Project Software	120,128	88,895	Non-Revenue	88,895	9.41%		8,365		8,365	4,183					
52			TOTAL COMMON INTANGIBLE	229,981	180,110		180,110	To KAS-2, Sch 2 col e, line 5		16,948	0	16,948	8,475	To KAS-2, Sch 2 col e, line 11	0	33.330%	60,031	43,083
53			TOTAL (ALL)	$2,983,278	$1,493,616		651,704			31,264 To KAS-1 Sch 3 col k, line 16	33,613	64,877	32,446		27,751 To KAS-1 Sch 3 col k, line 14		125,011	60,134
54																	DIT (35%)	21,047 To KAS-2, Sch 2 col e, line 23

1/ Combination of replacement, new, revenue and non-revenue producing.

Source:
Column a through f: MDU's response to DR1-10

Montana-Dakota Utilities Co.
Docket NG04-004
Plant Additions/Depreciation/Accum. Depr.
Adjusted Test Year Ending December 31, 2003

MONTANA-DAKOTA UTILITIES CO.
PLANT ADDITIONS - SUMMARY
GAS UTILITY - SOUTH DAKOTA
PRO FORMA 2004
Response to DR1-10

STAFF ADJUSTMENT
PLANT ADDITIONS

Project No.	Acct. No	Description	Projected Expenditures	Actual Expenditures Thru 7/31/04	Revenue/ Non-Revenue/ Replacement	Staff Accepted Plant Additions (acutal)	Staff Proposed Depr. Rates	Notes	Annual Depr. Exp. To Depr. Expense (new rates)	Annual Depr. Exp. To Clearing Accounts (new rates)	Annual Accumulated Depreciation (new rates)	Average Annual Accumlated Depreciation (new rates)	2003 Percent of Clearing Acct. Depr. To O&M (new rates)	Plant Addition Depr. Exp. To O&M (new rates)	Tax Depreciation		Excess Tax/Book Depr.
															Rate	Amount	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)

Column g: Non-revneue producing acutal expenditures for column e
Column h: KAS - 1 Schedule 5, page 2 of 2 column d
Column j: column g times column h
Column k: column g times column h
Column l: column j plus column k
Column m: column l divided by 2 (average balance
Column n: MDU response to DR 1-4, Att. A, support for Statement H, page 48 and 51
Column o: column k times column n

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

RECEIVED
OCT 19 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Montana-Dakota Utilities Co.
Application to Increase Gas Rates in South Dakota
Docket No. NG04-004

Testimony of Robert G. Towers on Behalf of the Commission Staff

October 2004

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Montana-Dakota Utilities Co.
Application to Increase Gas Rates in South Dakota
Docket No. NG04-004

Testimony of Robert G. Towers
on Behalf of the Commission Staff

October 2004

I. Qualifications

Q. Please state your name, business address and occupation.

A. Robert G. Towers. I am a public utility rate consultant and a principal in the firm Chesapeake Regulatory Consultants, Inc. ("CRC"). My office is at 6837 Guilford Road, Clarksville, MD 21029-1632. I can be contacted by telephone at 443.535.0300.

Q. Does the Appendix to this testimony describe your education and summarize your experience in public utility regulation?

A. Yes, it does.

Q. Have you testified previously before the South Dakota Public Utilities Commission?

A. Yes. Since 1976 I have testified on behalf of the Commission Staff in more than thirty rate cases involving each of the investor-owned gas and electric utilities in the state and U.S. West and I have consulted with the Staff in connection with other proceedings.

Q. Have you testified in or otherwise been involved in proceedings concerning the rates of Montana-Dakota Utilities Co. ("MDU" or "the Company")?

A. Yes. I testified for the Commission Staff in fourteen South Dakota rate cases involving MDU's electric or gas operations beginning with the 1976 electric case, Docket No. F-3053. Most recently, I assisted the Commission Staff and filed testimony in Docket No. NG02-011, involving MDU's gas rate increase filing of December 30, 2002.

I also testified on behalf of the Montana Consumer Counsel in two Montana rate proceedings involving MDU's gas operations, Docket Nos. 94.4.17 and 95.7.90.

II. Purpose of Testimony and Summary of Findings

Q. What is the purpose of your appearance in this case?

A. CRC was retained, specifically, to address issues related to the Company's cost of capital and the allowable rate of return and its proposed allocation of the requested additional revenue among the several classes of customers served. We also were asked to provide general assistance to the Staff in the conduct of its review of MDU's rate application and to provide testimony on revenue requirement issues, as needed.

My associate, Basil L. Copeland, Jr. has analyzed and is testifying on the Company's required return on common equity capital ("ROE") and the capital structure that is appropriate for determining a composite, weighted cost of equity and debt capital. The composite cost of capital is the rate of return to be applied to the Company's South Dakota gas operations rate base.

I have analyzed the class cost of service study (CCOSS) underlying the Company's proposed allocation of its claimed revenue requirement to customer classes. I will also address the proposed increases in monthly customer Service Charges.

I also assisted the Staff in reviewing various accounting issues entering into the determination of the Company's South Dakota revenue requirement. I will testify and make recommendations concerning one of these issues – the accrual rates used to determine appropriate allowances for the annual depreciation of the Company's plant investments.

Q. Briefly, what are your conclusions and recommendations?

A. ***Depreciation***
(See Exhibit___(RGT-1))

This is an issue on which I testified in MDU's earlier rate cases, initially in Montana and, most recently, in Docket NG02-011, where I concluded that the accrual rates which the Company was then using for two important accounts --

Account 376-Mains and Account 380-Services were excessive. Two events have occurred since that testimony was given. First, the Company commissioned a comprehensive study of its accrual rates based on plant in service at the end of 2001, updating the 1991 study underlying the rates which I had been challenging. The new study was completed by the Company's consultants and summarized in reports dated January 27, 2003. The rates recommended by the Company's consultants are the rates which it proposes to use in this case.

Second, at the time the new depreciation study was being completed the Company was involved in a rate case in North Dakota where its former depreciation rates were being challenged. Desiring to resolve the issue with the benefit of the new study, the North Dakota Commission continued its hearings to receive the new study with direct and rebuttal testimony. The evidentiary presentations culminated in a settlement which was approved by the Commission on July 31, 2003. The settlement accrual rates were implemented in North Dakota on September 1, 2003 coincident with the associated reduction in gas service rates.

I am recommending that the schedule of accrual rates adopted by the North Dakota Commission be implemented in South Dakota. Among other changes, the settlement adopts a rate of 1.92% for Account 376 - Mains, a substantial reduction in the 4.18% rate that I objected to in South Dakota Docket No. 02-011. For Account 378 - Services the settlement establishes a rate of 5.66% – again, substantially lower than the 8.22% rate to which I took exception in Docket No. 02-011. Overall, when applied to South Dakota plant, the settlement rates reduce MDU's test year gas and common plant depreciation expense by $338,350.

Class Cost of Service Study

(See Exhibit___(RGT-2))

I disagree with one important element of the Company's CCOSS, sponsored by Ms. Tamie A. Aberle. Ms. Aberle imputes a "customer component" to distribution Mains and allocates these costs among the classes on the basis of a combined factor reflecting the weighted number of Customers in each class (36% weight) and class peak single-day usage levels (64% weight). For several reasons which I will discuss later, I believe that the Customer component of this factor is not justified and that all of these Mains costs should be allocated among the classes on the basis of the peak usage factors.

This recommendation affects the allocations of Mains as well as other costs for which composite allocation factors are employed in the study. The effect of the recommendation is to shift costs away from the Residential class and to all other classes. My allocations show that, relative to the Company's study, the proposed rates would allow it to earn a much higher rate of return from Residential customers and much lower returns from Firm General service, and Small and Large Interruptible customers. Similar relationships are indicated even with MDU's present rates. These results lead to my recommendation that a much larger portion of any rate increase should be assigned to the three classes with deficient returns.

Customer Service Charges
(See Exhibit___(RGT-3))

I find the purported cost justification for the Company's proposed monthly Service Charges to be greatly overstated because it includes many costs that are not directly related to the service rendered to individual customers, including the customer component of Mains which I have described in my critique of the Class cost of service study. Other non-assignable, overhead-type costs that are treated by MDU as a "customer cost" represent activities that are required by the totality of all system functions and are independent of incremental changes in the customer population.

Furthermore, even after such indirect costs are purged from the analysis, it is not essential that the remaining direct customer-related costs be recovered through fixed monthly service charges; any costs not recovered in the Service Charge will be recovered in the non-gas commodity charge (the "delivery charge"). Also, putting such costs "at risk" by requiring that they be recovered in the delivery charge provides the Company with a cost control incentive.

My determinations of MDU's direct customer costs indicate that the presently-effective Service Charge for Residential customers is more than adequate and should not be increased in this case. In the future, as company ownership of service lines replaces customer ownership, its direct customer costs will increase and it might be necessary to increase this charge. For Firm General Service and Large Interruptible customers, my determinations indicate that the proposed Service Charges are cost-justified.

III. Depreciation

Q. Has MDU presented a study in this case to justify the depreciation rates it proposes to use?

A. No. However, during MDU's last South Dakota case (NG02-011), upon learning of the existence of a study completed in January, 2003, conducted for the Company by AUS Consultants based on plant in service and retirement activity through the end of 2001 (the "2001 study"), Staff requested and was supplied with a copy of the consultant's report. The 2001 study is the source of the rates the Company has used to determine its revenue requirements in this case. It began booking these rates in South Dakota on January 1, 2004.

In this case, Staff requested and was supplied with a copy of a settlement agreement entered into by MDU and the North Dakota Commission Staff after the submission of testimony critiquing the AUS study and the issuance of a Commission order accepting the settlement rates. The North Dakota proceeding testimony was also supplied to Staff. As I mentioned earlier the settlement accrual rates were implemented in North Dakota on September 1, 2003.

Q. Have you had an opportunity to review the AUS Consultant's January 2003 report and the North Dakota settlement rates and, if so, do you agree with the Company's decision in this case to adopt the consultant's recommended rates?

A. Yes, I have reviewed AUS's January 2003 reports, the North Dakota settlement rates and the testimony filed in North Dakota. The settlement rates reflect compromises of differing views aired in the North Dakota investigation. My review of all of this information leads me to conclude that, while, in certain important respects, the rates proposed in the AUS reports are an improvement over the rates they superseded, the rates agreed to and implemented in North Dakota are superior and should be applied in this South Dakota case.

Q. Please explain.

A. First, I should explain that both the AUS-recommended rates and the studies presented in the North Dakota proceeding challenging the AUS rates were developed from analyses of historical plant retirement activity, removal costs and salvage values experienced over MDU's system-wide Gas Division and Common plant operations. This includes its operations in North Dakota, South Dakota, Montana and Wyoming and there is no evidence to suggest that the rates were intended only for limited application. In fact, I understand that in an on-going

rate proceeding in Montana, MDU has consented, subject to the Montana Commission's approval, to adopt the depreciation rates that I am recommending in this case.

Overall, and notwithstanding the improvements I mentioned earlier, replacing the prior accrual rates with the new study rates would increase South Dakota test year (2003) annual depreciation expense and amounts charged through clearing accounts by about $225,000. Exhibit___(RGT-1), Schedule 1 shows that MDU's proposed accrual rates result in an expense of $2,161,572 while the pre-existing rates resulted in an expense of $1,936,695. The MDU-proposed accrual rates for the important Mains and Services accounts (3.15% and 7.03% respectively) – together representing $24 million, or 55% of all South Dakota 2003 test year depreciable plant – are lower than the rates they would replace (4.05% and 7.60%) bringing them more in line with the rates that I recommended for these accounts in NG02-011 (3.68% and 6.38%) based on my analysis of the Company's then-most recent actuarial study. However, the AUS-recommended, MDU-proposed rates for these accounts retain very significant, questionable and unnecessary allowances for negative net salvage.

The principal increase proposed in the 2001 study is an increase in the accrual rate for Gas plant Account 392.20 - Transportation Equipment (Cars and Trucks). That rate is raised from 5.74% to 21.13%, increasing the test year depreciation allowance for vehicles by $289,342.

The North Dakota settlement reduced significantly the AUS-recommended rates for Mains and Services and ameliorates my concerns that those rates contain excessive allowances for negative salvage. The settlement rates are 1.92% for Mains and 5.66% for Services. Thus for these two accounts alone, using the settlement rates rather than the 2003 study rates reduces South Dakota test year depreciation expense by $303,554. The settlement does not modify the proposed rate for Account 392.20 - Transportation Equipment (Cars and Trucks). The 21.13% rate appears to be reasonable as it is based on a five year average service life, a twenty percent positive salvage allowance (trade-in value) and recognizes the age of the existing fleet and depreciation accrued at the much lower prior rate as of the date of the study. Applying the entire schedule of rates agreed to in the North Dakota settlement reduces South Dakota 2003 test year depreciation expense (including clearing accounts) from $2,161,416 at MDU's proposed accrual rates to $1,823,222, or by $ 338,350. The North Dakota settlement rates are shown in Column (F) on Schedule 1 of Exhibit___(RGT-1); the annual depreciation expense reflecting these rates is calculated in Column (I).

Q. What is "negative net salvage"?

A. "Negative net salvage", or "negative salvage", describes the condition in which removal costs incurred when plant is retired from service exceeds the value of recovered materials. The factor (60% for Mains; 175% for Services in the accrual rates proposed by AUS and reflected in MDU's determination of its revenue requirement in this case) expresses the level of net negative salvage as a percentage of the original cost of the plant being retired.

For example, the Company's investment in distribution Mains in South Dakota during the 2003 test year averaged $18,488,541. A 60% negative salvage allowance implies that upon the retirement of this plant, the Company will incur more than $11 million of removal costs in excess of its scrap value. The Company's proposed depreciation rates are set to recover these amounts over the estimated remaining lives of the plant in the account.

Q. Please explain your concerns with the large allowances for negative salvage that are reflected in the rates for Mains and Services that the Company proposes to use in this case.

A. In 1993-94 when I reviewed the 1991 gas plant depreciation study commissioned by MDU I concluded that the salvage allowances then being proposed for Mains (a negative 40%) and Services (a negative 140%) were neither appropriate nor were they necessary to provide for full recovery of the Company's investments in this plant. The AUS 2003 study report recommends rates for these accounts that reflect even larger negative salvage allowances – a negative 60% for Mains and a negative 175% for Services.

Q. Why do you believe that the negative salvage allowances for these accounts are inappropriate and unnecessary?

A. The negative salvage allowances are not based upon any estimate of the costs that actually will be incurred upon the retirement of the plant that is presently in service and it is highly unlikely that the implied removal costs will be incurred.

The AUS analyses underlying the proposed rates, are based on observations of the piecemeal retirements that have occurred on MDU's gas distribution system in recent years with the net salvage estimates derived by associating removal costs and salvage values at current price levels with investments in the retired plant stated at historic, original cost price levels. In addition, the experienced salvage and removal costs are associated with

materials that differ from the materials now used for Mains and Services even though the accrual rates are to be applied to plant investments in both the old and new materials.

Furthermore, the salvage experience studied by AUS was quite small relative to the investment for which the salvage estimates were being made. For example, for Mains the Company's experience over the 33-year period, 1968-2001 was studied. During this time, the Company retired plant in which it had an investment of $6.0 million; this was less than 8% of the $78 million of Mains that were in service at the time the study was conducted.

Even more important than the aggregate amount of the retirements reviewed in the 2001 study is the size of the retirement projects. This is significant because, while there will continue to be piecemeal retirements on the system, some consideration should be given to the eventual wholesale retirement of the system, or portions thereof, due to supply restrictions, competition or technological changes. Reasonably, such retirements can be expected to result in economy of scale savings in removal costs.

The AUS study did not analyze individual retirement projects but, instead, aggregated all retirements occurring in each year during the study period. Nevertheless, even the annual data demonstrate that the projects were quite small relative to the plant exposed to retirement. For instance, in the last year examined, 2001, the Company's investment in gas distribution Mains was $78.3 million (the plant exposed to retirement) while only $171,000 of Mains were retired. Gross salvage is reported as zero in that year with removal costs amounting to $74,000. Removal costs incurred over the entire 31 year period amounted to less than $2 million – a very small sample from which to hypothesize that depreciation accrual rates should be designed to recover removal costs of $47 million (60% of the $78.3 million system-wide investment in Mains at the end of 2001).

Q. Is historical retirement and salvage cost necessarily a sound basis for hypothesizing future costs?

A. No. The fundamental objective of depreciation accounting is to recognize over the expected life of the plant all of the costs associated with that plant. These costs include the initial plant investment, interim additions and any costs that will be incurred to remove the plant from service. Thus, in the strictest sense, the appropriate cost of removal allowance for an item of plant in service has nothing to do with currently experienced or historical relationships of retirements and

removal costs. But the future conditions and events that will determine the actual removal costs are not now known with any level of confidence. Conditions under which future retirements will take place are continuously changing[1] and the expected service lives of utility plant are quite long. If there is reason to believe that the past experience is unlikely to be repeated -- as is the case with long-lived utility plant -- the past relationships should be regarded with suspicion.

Q. Have others recognized the difficulty of estimating future salvage and plant removal costs?

A. Yes. The NARUC's depreciation handbook, Public Utility Depreciation Practices, indicates that "[c]ertain regulatory agencies consider only gross salvage in depreciation studies and require that costs of removal be included as expenses in the year they are incurred." The Pennsylvania PUC adopted this practice because of the high level of uncertainty in forecasting plant removal costs.

Also, I note that, like other corporate taxpayers, for Federal income tax purposes, MDU deducts plant removal costs when and as they are incurred rather than estimating these costs during the active service life of the plant (see tax deduction for "Expenses for the Retirement of Assets" reported on Statement K, Schedule K-1, page 2 of MDU's filing in this case).

Q. You indicated that recent salvage experience may not be indicative of the long-term future because of changes in piping materials. Have others recognized that salvage and plant removal costs might vary depending on the materials involved?

A. Yes. The NARUC's Depreciation Practices manual instructs that:

> "These [historic] trends should not be considered the sole guide in predicting future salvage. Recognition should be given to changes that may cause deviations from past trends, such as the kinds of material to be removed in the future versus the kinds that have been removed, or changes in methods of removing plant from the way in which that plant had previously been removed..." [Emphasis added.]

[1] Examples include changes in requirements imposed by public authorities, changes in construction and removal methods, and changes in the relative price levels between the time of the plant's construction and the time of its retirement.

Q. Does MDU's system contain different materials?

A. Yes. In fact, the AUS study recognizes the existence of the different piping materials in estimating average service lives of Mains and Services, but its salvage estimates examine only the combined experience in each account.

Q. Please explain.

A. The salvage and cost of removal experience relied on in the AUS is heavily weighted with the cost of removing now superseded steel piping. The adoption of plastic pipe as the "material of choice" for new installations and replacements and the accelerated removal of unprotected steel pipe by MDU (see Exhibit___(RGT-1), Schedule 2, pages 1 thru 4) means that the composition of the investment to which the depreciation rate will be applied is shifting away from steel and toward plastic pipe. Obviously the application of a removal cost estimate based on experience with steel pipe to an investment base representing primarily plastic pipe is a major shortcoming in the AUS analysis.

Q. You mentioned economies of scale that could be experienced with larger retirement projects. What scale economies are possible?

A. MDU is permitted to abandon Mains and Services in place. Exhibit___(RGT-1), Schedule 2, pages 5 and 6 explain that, in general, the Company removes the existing pipe only when leaving it in place interferes with new construction. Obviously, retirement of a large section of the system for reasons of competitive obsolescence or exhaustion of gas supplies would not require it to incur much of the removal cost that would be incurred for a replacement. The facilities would be abandoned in place.

Q. Is it relevant to consider such a retirement in setting depreciation rates for plant that is more likely to be replaced?

A. Yes, I believe that it is relevant to consider the "ultimate retirement" but I would not rely entirely upon this scenario -- first, because such costs would be at least as speculative as the estimates of removal costs associated with interim replacements and, secondly, because I believe it is appropriate for current ratepayers to make some contribution to the removal costs that are likely to be incurred in the interim as plant is replaced.

Q. Having explained your concerns that the negative salvage allowances reflected in the accrual rates recommended in the AUS report are excessive, what are the

salvage allowances reflected in the North Dakota settlement rates that you are recommending in this case?

A. The settlement rates reflect a compromise of positions. There is nothing in either the Settlement Agreement or in the Commission's order approving the agreement that identifies the elements of the accrual rates that were negotiated. If one were to assume that the entire difference in the accrual rates for the Mains and Services accounts were attributable to a change in the salvage estimates, the accrual rates would imply salvage allowances of a positive 2% (gross salvage exceeds removal costs) for Mains and a negative 40% for Services. More likely, the settlement rates reflect a combination of adjustments to average service lives and salvage estimates.

Q. Are you confident that the settlement rates in their entirety applied to the Company's South Dakota plant in this case satisfy the objectives of providing MDU with a reasonable opportunity to recover it plant-related investment costs over the useful life of the plant and that they do not burden its South Dakota gas customers with unreasonable costs or a disproportionate share of those costs?

A. Yes. MDU's willingness to accept the settlement rates in a proceeding where depreciation rates were the sole issue and the fact that the rates derive from a study of its system-wide plant indicates to me that the Company's interests should be satisfied. Because the settlement rates appear to have remedied the concerns that I have aired here and in prior MDU gas proceedings, I believe the settlement rates will not burden South Dakota with unreasonable costs.

V. Class Cost of Service Study

Q. What is a class cost of service study?

A. A class cost of service study is a functional analysis of the utility's operations and costs by which the analyst measures the relative responsibility of each customer class for the utility's total annual cost of service or revenue requirement. The results of the cost of service study are used to determine how the utility's presently-effective service rates should be adjusted to achieve equity between the utility and its customers and among the utility's various classes of ratepayers. Also, information obtainable from the class cost of service study can be used to establish specific rate elements.

Q. Did MDU prepare a class cost of service study for this case?

A. Yes. The cost of service study is incorporated in its rate filing as Schedule N, with three parts consisting of 36 pages. The study is sponsored by the Company's Pricing and Tariff Manager, Ms. Tamie A. Aberle.

The Company's embedded cost study is presented on two bases -- one reflecting its operating results for the Year ended December 31, 2003 and the other reflecting its claimed Pro Forma 2004 costs. The results are summarized on pages 8 (2003) and 4 (2004) of Schedule N-1. The 2004 cost study reflects the operating expenses and rate base investments that constitute MDU's claimed South Dakota revenue requirement, summarized on page 3 of Ms. Rita Mulkern's Exhibit___(RAM-1). This is the revenue requirement which leads to the Company's request for a rate increase target of $1,282,133 using the Pro Forma 2004 test year. The rate increase produced by the proposed rates is slightly less, $1,281,417.

Ms. Aberle's cost study allocates the annual revenue requirement among six classes of customers including the large classes of Residential and Firm General service customers and the smaller Firm Contract, Air Force, Small Interruptible and Large Interruptible users.

Q. What are the rate increases proposed by the Company based on its class cost study?

A. The Company is proposing rates that are said to result in a $1,281,417 increase in annual revenues based on its projection of 2004 sales volumes -- a 2.2% increase in existing rate revenue, including the June 2004 Purchased Gas Cost Adjustment ("PGA") (Exhibit No.___(TAA-1). The entire increase is proposed to be recovered from Residential, Firm General service and Large Interruptible classes because its class cost of service study suggests that the return on rate base earned from all other classes exceeds its claimed return. The Company proposes to increase Residential rates by 2.89%, Firm General service by 2.01% and Large Interruptible by 1.02%.

As I mentioned, these percentage increases represent, for each class, the impact of the proposed rate changes on total class revenues, representing the customers' total bills. However, the proposed rate increase affects only those revenues collected through customer Service Charges and Distribution Delivery charges (together referred to as "Distribution revenues"); the increase is not related to changes in the Company's gas supply costs and the filing proposes no change in the PGA portion of Residential, Firm General service or Large

Interruptible customer billings. A more meaningful assessment of the size of the rate increase requires comparing the proposed increase to the Distribution revenues generated with present rates. This comparison indicates that the Company's proposal would increase these revenues by 11% for Residential, 12% for Firm General service and 4.9% for Large Interruptible customers. Increases of this magnitude are questionably large when one considers that MDU's present rates have been in effect for less than one year.

Q. What is your assessment of the Company's class cost of service study and its application in the determination of the proposed rates for each class?

A. I do not disagree with many aspects of Ms. Aberle's cost analysis, but I do not agree with her treatment of a significant portion (36%) of distribution Mains as being related to the number of customers served. These so-called "customer-related" costs are allocated among the customer classes on the basis of the relative number of customers served in each class while the remaining Mains' costs (64%) are allocated on the basis of each class' requirements for pipeline capacity, measured by class usage during the 2003 test year peak day.

The effect of the Company's treatment of these costs is to overstate the total costs allocated to Residential customers and to understate costs to other classes. The use of these overstated costs to design the proposed rates places a larger-than-justified share of the proposed rate increase on these customers.

Q. Why is it not appropriate to treat these costs as customer-related and to allocate them among the classes on the basis of the relative number of customers in each class?

A. The concept that each customer is responsible for an equal amount of the cost of this portion of Mains is inconsistent with the manner by which these costs are incurred by the gas utility and it is unrelated to the gas customer's service objectives. Also, the determination of that portion of the cost of Mains which is deemed to be customer-related is hypothetical and unreliable.

Gas distribution networks generally are the result of system expansion over long periods of time into new service territories in response to area development. The networks are expanded, periodically,

into new territory to satisfy the aggregate gas service requirements of the service areas, reflecting a mix of customer types and end uses. They also grow to satisfy changes in the requirements of customers in existing service areas. Obviously, customers are attached to the network individually but the distribution system is designed and constructed to serve an aggregation of loads -- or potential loads -- in a geographical area. In addition, from the customer's perspective, the distribution Mains are desired to obtain a supply of gas -- not as a facility that exists merely for access to the pipeline network.

Furthermore, unlike a meter, regulator and service line which are dedicated in their entirety to a single customer, there is no physically identifiable "customer component" of Mains. MDU creates this component by hypothesizing a system of "zero or minimum size main necessary to connect a customer to the system" (see Exhibit___(RGT-2), Schedule 4). This hypothetical system is the length of the piping constituting MDU's four-state distribution systems at December 31, 2001 (2,301 miles of steel Mains plus 2,163 miles of plastic Mains) priced at either the average cost per foot of the smallest size pipe of that material or at the "zero intercept" cost per foot gleaned from the relationship of pipe sizes to cost. The zero intercept purports to represent the theoretical cost of a Main with no capacity. As indicated at the bottom of the second page of Schedule 4, plastic mains are priced at the cost per foot of the smallest size pipe (0.5 inch @ $0.86520 per foot) while steel mains are priced at the zero intercept cost of $1.49489 per foot to calculate a Total Customer Component of $28,043,257 which is 35.8% of the total Mains investment at the end of 2001.

But any number of greatly varying conclusions can be drawn from MDU's data – all hypothetical and unreliable. For example, if steel mains had been priced -- as plastic was priced -- at the minimum size cost level ($0.73865 per foot) instead of the zero intercept cost ($1.49489), the Total Customer Component would have been lower by $9.2 million ([$1.49489 minus $0.73865] times 12,150,547 feet). Or, if steel had been priced at the cost used for plastic pipe -- in recognition of the fact that plastic is superseding steel and that the purpose of this theoretical exercise is merely to connect customers -- the Total Customer Component would have been lower by $7.7 million. Moreover, although the cost per foot for plastic pipe is indeed the cost per foot of the smallest size plastic pipe, it is not the lowest cost; the cost per foot of 1.25 inch pipe is modestly lower. And, in any event, one would have to recognize that either size of plastic pipe (0.5 or 1.25 inch) has delivery capacity – a fact that is inconsistent with the effort to identify a pure "customer component".

Q. Are there other problems with the "minimum system" hypothesized by MDU?

A. Yes. Another conceptual defect is the supposition that an efficient "minimum system" would measure 4,464 miles in length. This mileage represents MDU's existing systems built over many years. At December 31, 2001, the date of the AUS Consultants depreciation study which I referred to earlier in my testimony, some of the surviving Mains had been installed as early as the late 1920's. Obviously, the system was built in response to changing requirements *as the needs arose*; such as system is unlikely to represent the "minimum system" that would be required merely to connect to now-existing customers.

Q. If it is not appropriate to allocate these costs on a customer basis, how should they be classified and allocated?

A. The allocation method should recognize the relative service requirements imposed by customers inasmuch as the system has been designed and constructed -- and costs incurred -- to satisfy these gas delivery requirements. Consequently, I would allocate Mains on the basis of customers' use of the system, measured either by their volumetric requirements (annual "throughput") or maximum requirements (e.g. peak use requirements). Because distribution Mains must be built large enough to satisfy peak requirements, thereby increasing their cost, I recommend that they be allocated on the basis of class peak demands -- in this case I would use the test year Peak day factor that is the second component of the Company's allocation factor.

Q. How does the change in allocations that you are proposing affect the cost of service by rate class?

A. Schedule 1 of Exhibit___ (RGT-2) is a recalculation of the Pro Forma 2004 class cost of service study presented by Ms. Aberle and summarized in Statement N, Schedule N-1, page 4. My recalculation reflects only one change in MDU's calculations – use of the Peak day factor alone to allocate Mains in place of the composite Customer/Peak day factors used by Ms. Aberle. Of course, changing that factor affects the allocation of other costs that follow the Mains allocation.

The Total South Dakota column on my Schedule 1 matches the corresponding column in Ms. Aberle's cost study; both indicate an overall rate of return earned of 5.264% before any rate increase. The effect of the change in allocations is reflected in the following comparisons of the rates of return earned by each class.

Customer Class	Rate of Return Earned w/Present Rates MDU Allocations	Staff Allocations
Residential	4.516%	6.589%
Firm General	5.283	2.371
Firm Contract	29.951	14.378
Air Force	23.397	23.397
Small Interruptible	11.855	8.391
Large Interruptible	7.887	1.928
System	5.264%	5.264%

The implications of these returns are two-fold. First, both allocation studies indicate that existing rates applicable to Firm Contract and Air Force customers result in earnings that are well above either the Company or Staff-recommended rate of return (MDU's 9.61% or Staff's 8.734%). Moreover, Staff's adjustments to the Company's claimed system revenue requirement would increase the earned returns from all classes.

Second, the allocation method that I propose shifts costs away from the Residential class and to all other classes (except the Air Force).

Q. Incidentally, Mr. Towers, does your use of the Company's Pro Forma 2004 cost study represent an endorsement of that period as a test year or of the Company's claimed revenue requirement?

A. No. I have used the Company's cost of service study to illustrate the differences between the two allocation methods, unaffected by differing positions on issues related to the test year or total revenue requirement. For its determination of revenue requirements, Staff is using a test year based on actual operating results for the year ended December 31, 2003 adjusted for known and measurable changes and has made an independent determination of the required rate increase. This increase is summarized in the testimony and exhibits of Staff witness Keith A. Senger.

Q. What are the implications of your allocation study on the distribution of any rate increase that might be justified?

A. As explained by Ms. Aberle, MDU has proposed to allocate its claimed revenue deficiency of $1,281,417 by first increasing the Firm General service customers rates, as well as the rates to Large Interruptible customers, to produce,

approximately, the 9.61% overall rate of return it is claiming. The remainder of the requested total increase is assigned to the Residential class. By this process, Residential customers are the beneficiaries of the higher-than-requested returns earned from Firm Contract, Air Force and Small Interruptible customers.

The rates of return earned from each class with the Company's proposed rates, and reflecting its cost allocations, are reported on page 1 of Statement O, of MDU's Schedule O-1. I have summarized these returns on page 2, Schedule 2 of Exhibit___(RGT-2). Schedule 1 of Exhibit___(RGT-2) shows the corresponding rates of return based on my cost allocations.

The rates of return indicated by my allocation study dictate that a larger proportion of any rate increase should be assigned to Firm General service and Large Interruptible customers and that there be some increase in the rates to Small Interruptible customers.

Q. Can you illustrate how this would be accomplished?

A. Yes. Schedule 3 of Exhibit___(RGT-2) develops, on two bases, a revised distribution of the Company's proposed $1,281,417 rate increase. Page 1 of Schedule 3 follows the Company's methodology of (1) increasing the rates to the non-Residential classes with deficient returns to the levels required to earn the objective rate of return and (2) assigning the remainder of the total proposed rate increase to the Residential class. As I mentioned before, the approach gives Residential customers the benefit of the above-objective returns earned from the Air Force and Firm Contract customers. It also means that the rate of return earned from the Residential class is below the objective rate of return.[2]

Q. Why did you explore an alternative to this distribution of the Company's proposed rate increase?

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[2] Lines 1 and 2 of Schedule 3 are from my cost allocation study summarized on Schedule 1. The class rate increases proposed by Ms. Aberle are reported on line 3. The additional income produced by the proposed increases (line 5) is added to the income earned with present rates (line 2) and the resulting rates of return are shown on line 7. Lines 8 thru 10 develop the additional revenue required to raise the returns earned from Firm General service and Small and Large Interruptible customers to the target level in the illustration (9.61%). These amounts are combined with the increases proposed by MDU to obtain the adjusted increases on line 12. Deducting applicable income and revenue taxes and then combining the earnings resulting from the modified rate increases with the earnings produced with present rates yields the operating income(line 15) and rates of return (line 16) that would be produced by the new rate levels.

A. Relative to the Company's proposed distribution (and proposed rates), the distribution illustrated on page 1 of Schedule 3 substantially reduces the impact of the increase on Residential customers and increases the impacts on the Firm General service and Small and Large Interruptible classes. This is illustrated on Lines 18 and 19 of the spreadsheet. For example, the Company-proposed 2.01% increase to Firm General service customers is nearly doubled at 3.93% while the Company-proposed 2.89% increase to Residential users is reduced to 1.60%. Recognizing that this change is due in part to assigning all of the above-target earnings from the Air Force and Firm Contract customers to the Residential class, I thought it appropriate to explore the option of assigning the above-target returns to classes adversely affected by my proposed cost allocations. This is the approach reflected in the distribution developed on page 2 of Schedule 3 of Exhibit___(RGT-2).

Q. Please explain the calculations on page 2.

A. Lines 1 through 7 are identical to the same lines on page 1, developing in columns (B) through (H), the rates of return earned with the distribution proposed by MDU and reflecting my cost allocations. Column (I) summarizes this information for the classes with below-objective returns.

Overall (column (B)), the Company's objective rate of return (9.61% on line 16) requires a net operating income of $1,837,530 (line 15). Assigning the same objective return to the Residential class requires earnings from this group of $1,094,881. Deducting this amount and earnings from the Firm Contract and Air Force customers from the $1,837,530 total return requirement leaves $683,338 to be recovered from the combined Firm General service and Interruptible classes (column I, line 15) – equivalent to a 9.32% rate of return from this group. The rate increases required from each of these classes to produce the 9.32% return are developed in columns (D), (G) and (I).

Q. Which of the rate increase distributions developed in Schedule 3 do you recommend?

A. I recommend the distribution developed on page 2 because it mitigates the larger-than-average rate increases that otherwise would be assigned to Firm General service and Large Interruptible customers and reduces the increase to Small Interruptible customers, for whom the Company had proposed no rate

increase.[3] Moreover, it achieves these benefits without increasing the return requirement assigned to Residential customers above the objective rate of return.

Q. How would you apply this recommendation to the Commission's determination of the rate increase required by MDU?

A. Ideally, the class cost of service study would be rerun incorporating all of the test year revenue, expense, rate base and rate of return components reflected in the determination of the required rate increase. The distribution of the rate increase could then be made following the procedure used on page 2, Schedule 3 of Exhibit___(RGT-2). A simpler procedure, and a reasonable proxy for this approach, would be to distribute the system increase in proportion to the increases developed on page 2 of Schedule 3.

Using Staff's determination of the overall revenue requirement and required rate increase to illustrate this procedure, I would recommend the following distribution.

	Distribution of Increase Developed in Exh.___(RGT-2)*		Distribution of Staff-Recommended Increase
	Amount	% of Total	
Residential	$ 530,861	41.418	$ 87,161
Firm General	709,614	55.364	116,509
Firm Contract	-		-
Air Force	-		-
Small Interruptible	5,736	0.447	942
Large Interruptible	35,514	2.771	5,831
System total	$1,281,725**	100.000	$ 210,443

* Reflects Company claimed revenue requirement and Staff CCOSS.
** Total does not agree with Company-proposed $1,281,417 due to rounding.

[3] Compare the impact analyses on lines 17 and 18 of page 2 with the corresponding data on page 1 of Schedule 3.

VII. Customer Service Charges

Q. What changes has the Company proposed in its monthly customer Service Charges?

A. The Company proposes to increase the per day "Basic Service Charge" applicable to Residential customers from $0.25 to $0.26, resulting in an increase of 30.4 cents in the customer's bill (average month). For Firm General service customers with small meters (about 75% of this group), the proposed increase is from $0.33 to $0.35 and for those with larger meters the increase would be from $0.66 to $0.70, thus maintaining the doubling of the small meter charge. For Large Interruptible customers, existing rates of $175 (Sales customers) and $200 (Transportation service) are increased by $25.

Q. Are these charges cost-justified?

A. The proposed Residential Service charge is not cost-justified. The revenues produced in the aggregate by the other Service charges proposed by Ms. Aberle are supported by determinations of the associated customer costs.

Q. Please explain.

A. The purported cost justification for the Company's proposed Service Charges is found on pages 1 through 3 of Statement N, Schedule N-1. For example, page 1 tabulates the costs for Residential and Firm General service customers which, in its comprehensive class cost of service study, are classified as "Customer" costs and allocated to these groups. The cost per customer per month for Residential customers of $16.192 is the Company's justification for the proposed charge of $0.26 per day, or $7.90 for an average month. Similarly, the $39.344 cost per customer is its justification for the $0.33 ($10.03 monthly) and $0.66 ($20.06 monthly) charges to Firm General service customers.

These "Customer" costs are greatly overstated. In addition to the fact that the costs are based on all of the Company's Projected 2004 cost claims in this case, many of the costs reflected in the class cost of service study do not vary as customers are added or leave the system. It is neither necessary nor appropriate to require that such costs be recovered in a fixed monthly (or daily) service charge.

Q. What are some of the costs that do not vary as customers are added or removed?

A. The costs that do not change incrementally as the number of customers may change include the customer component of Mains (which I have recommended be reclassified as demand-related), administrative costs and various overhead-type costs. This is to be contrasted with other costs that would change significantly with the number of customers, such as the cost of installed meters, regulators and service lines.

Q. Please explain.

A. The cost of service associated with distribution Mains would be unaffected by the addition of a customer that can be connected with a service line that taps into the Company's existing distribution network. Main extensions are typically made when they are deemed to be economically feasible, which means supported by revenues from multiple customers (or contributions in aid of construction). In my view, as I explained in discussing the class costs of service study, Mains costs do not have a customer component and, in any event, no portion of Mains should be treated as a "customer cost" in establishing a fixed-rate monthly service charge that would generate increased or decreased revenues for the Company as the number of customers changes.

Similarly, overhead costs are not driven by any demand for more or fewer service lines; they are related to Services only in the sense that the Services function is one of the functions required for the operation of the Company's integrated gas distribution system and the overhead costs are required by the totality of these functions. The fact that it is necessary in preparing a class cost allocation study to devise a method of allocating *all* of these costs *among* customer classes does not require that the overhead-type costs be considered in designing the rates *within* each class.

Q. How should one measure the costs that properly might be recoverable in a monthly service charge?

A. I would limit a customer service charge to the costs that are *directly* related to a customer's attachment to the system. These are the categories of costs that would be affected, incrementally, when a customer is added to the system. The costs would include the carrying charges on investment and the operating expenses related to customer Services, Meters and Regulators as well as the costs of meter reading and billing.

Q. Is it necessary to recover all of these costs through the service charge?

A. No. While all of these costs could properly be recovered in a monthly service charge, they need not be recovered in this manner. Obviously, assigning a portion of these costs to the Distribution Delivery rate would still allow them to be recovered by the Company.

Q. Have you made a determination of MDU's direct customer-related costs in this case?

A. Yes.

Q. What does your analysis show?

A. Exhibit ____ (RGT-3) shows my determination of these costs for each class based on the Company's Pro Forma 2004 class cost of service study, as modified to reflect my allocation of Mains and summarized on Schedule 1 of Exhibit___(RGT-2).

The direct customer costs summarized in my calculations include the return and related income taxes on the Company's rate base investments in Services, Meters and Regulators; the operation and maintenance and depreciation expenses associated with the same facilities; and all customer accounting and meter reading expenses. Moreover, I emphasize that the cost levels reflected in Exhibit___(RGT-3) are the Company's claimed costs, not the lower costs reflected in Staff's determination of MDU's revenue requirement.

Q. How do your determinations compare with those made by the Company and with the Company's proposed rates?

A. By focusing on the costs that are directly related to maintaining customer service, my determinations indicate customer costs for Residential customers of $6.24 per customer per month, or $0.205 as a daily cost; this contrasts with the $16.92 monthly cost developed by Ms. Aberle and with MDU's proposed $0.26 daily rate. Since the present rate of $0.25 already exceeds the $0.205 cost, I conclude that no further increase is justified.

For the Firm General service customers I determine the customer costs to be $17.64 monthly, or $0.58 on a daily basis. This suggests that, in the aggregate, the Company's proposed rates of $0.35 and $0.70, averaging $0.44 based on the present 75/25% customer mix, is cost justified. The same

conclusion is drawn for the rates proposed for the Large Interruptible class where the cost is shown to be $254 per month, supporting rates of $200 or $225.

Q. I have no further questions at this time, Mr. Towers.

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Depreciation Rate and Accrual Comparison
Test Period Ended December 31, 2003

Acct. No.	Account	Per Books Average plant	Depreciation Accrual Rates			Annual Depreciation Expense			
			Pre-Existing	MDU Proposed	ND Settlement	Pre-Existing	MDU Proposed	ND Settlement	
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
	Distribution Plant								
374.1	Land	$30,114							
374.2	Rights of way	8,609	2.58%	0.75%	0.75%	$222	$65	$65	
375	Structures and improvements	38,555	2.40%	3.24%	2.57%	925	1,249	991	
376	Mains	18,488,541	4.05%	3.15%	1.92%	748,786	582,389	354,980	
378	Meas. & Reg. Equip - general	251,431	2.30%	3.31%	2.96%	5,783	8,322	7,442	
379	Meas. & Reg. Equip - City Gate	68,586	2.74%	4.33%	3.54%	1,879	2,970	2,428	
380	Service	5,558,054	7.60%	7.03%	5.66%	422,412	390,731	314,586	
381	Positive meters	6,163,183	2.58%	3.19%	3.19%	159,010	196,606	196,606	
383	Service regulators	862,652	2.37%	2.87%	2.59%	20,445	24,758	22,343	
385	In. Meas. & Reg. Station equip	63,429	1.91%	3.77%	3.04%	1,211	2,391	1,928	
386.2	Other property on cust. Premise	170,931	9.35%	3.70%	5.19%	15,982	6,324	8,871	
387.1	Cathodic protection equipment	66,245	5.21%	5.75%	5.75%	3,451	3,809	3,809	
387.2	Other distribution equipment	86,342	5.21%	1.42%	1.42%	4,498	1,226	1,226	
	Total distribution plant	$31,856,672				$1,384,604	$1,220,840	$915,275	
	General Plant								
389	Land	$581,498							
390	Structures and improvements	3,772,881	2.34%	4.61%	3.73%	88,285	173,930	140,728	
391.1	Furniture and fixtures	295,607	4.05%	4.97%	4.97%	11,972	14,692	14,692	
391.3	Computer equip. - PC	246,293	12.50%	26.02%	26.13%	30,787	64,085	64,356	
392.1	Trans. Equip., Non-unitized	35,860	5.74%	4.36%	4.36%	2,058	1,563	1,563	Note 1
392.2	Trans. Equip., Unitized	1,880,067	5.74%	21.13%	21.13%	107,916	397,258	397,258	Note 1
393	Stores equipment	51,222	0.90%	2.49%	2.49%	461	1,275	1,275	
394.1	Tools, Shop & gar. Eq. - Non-Un.	433,458	3.57%	6.62%	6.62%	15,474	28,695	28,695	
394.2	Tools, Shop & gar. Eq. - Unitized	40,974	4.83%	2.40%	2.40%	1,979	983	983	Note 1
394.3	Vehicle maintenance equip.	7,627	4.21%	5.78%	5.78%	321	441	441	
394.4	Vehicle refueling equip.	102,233	9.35%	4.72%	4.72%	9,559	4,825	4,825	
395	Laboratory equipment	31,268	2.32%	7.67%	7.67%	725	2,398	2,398	
396.1	Work equipment trailers	96,572	4.83%	5.76%	5.76%	4,664	5,563	5,563	Note 1
396.2	Power operated equipment	1,362,281	4.83%	0.00%	0.00%	65,798	0	0	Note 1
397.1	Radio Comm. Equip. - Fixed	97,627	3.67%	7.37%	7.37%	3,583	7,195	7,195	
397.2	Radio Comm. Equip. - Mobile	126,007	3.67%	7.34%	7.34%	4,624	9,249	9,249	
397.3	General Tele. Comm. Equip.	36,547	6.56%	9.88%	9.88%	2,397	3,611	3,611	
397.5	Supervisory & Tele. Equip.	42,389	6.67%	0.25%	0.25%	2,827	106	106	
397.6	Scada system	385	15.07%	0.00%	0.00%	58	0	0	
397.8	Network equipment	21,251	12.50%	26.26%	26.26%	2,656	5,581	5,581	
398	Miscellaneous equipment	21,445	0.59%	1.27%	1.27%	127	272	272	
	Total general plant	$9,283,492				$356,271	$721,722	$688,791	
303	Intangible plant - General	$136,892	0.54%	0.54%	0.54%	739	$739	739	Note 2

Acct. No.	Account	Per Books Average plant	Depreciation Accrual Rates			Annual Depreciation Expense			
			Pre-Existing	MDU Proposed	ND Settlement	Pre-Existing	MDU Proposed	ND Settlement	
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
	Common Plant								
389	Land	$33,701							
390	Structures and improvements	426,442	3.76%	2.93%	2.93%	16,034	$12,495	12,495	
391.1	Furniture and fixtures	142,275	1.48%	4.95%	4.95%	2,106	7,043	7,043	
391.2	Computer Equip. - Bull/AS400	3,945	14.17%	1.52%	1.52%	559	60	60	
391.3	Computer Equip. - PC	234,756	12.50%	23.29%	23.29%	29,345	54,675	54,675	
391.4	Computer Equip. - EMS	419	0.00%	0.00%	0.00%	0	0	0	
391.5	Computer Equip. - Other	31,797	26.51%	0.46%	0.46%	8,429	0	146	
392.1	Trans. equip., non-unitized	1,754	5.74%	0.00%	0.00%	101	0	0	Note 1
392.2	Trans. equip. unitized	55,783	5.74%	13.33%	13.33%	3,202	7,436	7,436	Note 1
392.3	Aircraft	227,501				13,373	13,373	13,373	Note 1
393	Stores equipment	303	3.36%	2.80%	2.80%	10	8	8	
394	Tools, Shop & gar. Equip	2,139	3.44%	6.11%	6.11%	74	131	131	
394.3	Vehicle maint. Equip.	6,976	4.46%	4.75%	4.75%	311	331	331	
394.4	Vehicle refueling equip.	7,618	8.42%	4.38%	4.38%	641	334	334	
396.2	Power operated equipment	1,849	4.83%	2.69%	2.69%	89	50	50	Note 1
397.1	Radio Comm. Equip - Fixed	12,102	4.33%	4.99%	4.99%	524	604	604	
397.2	Radio Comm. Equip - Mobile	20,016	6.68%	4.08%	4.08%	1,337	817	817	
397.3	General Tele. Comm. Equip.	30,964	10.62%	8.72%	8.72%	3,288	2,700	2,700	
397.5	Supervisory & Tele. Equip.	167	0.59%	0.35%	0.35%	1	1	1	
397.8	Network equipment	47,517	12.50%	17.95%	17.95%	5,940	8,529	8,529	
398	Miscellaneous equipment	33,317	2.51%	2.41%	2.41%	836	803	803	
	Total common plant	$1,321,341				$86,200	$109,390	$109,536	
303	Intangible plant - common	$1,157,079	9.41%	9.41%	9.41%	108,881	$108,881	108,881	Note 2
	Total gas plant in service	$43,755,476				$1,936,695	$2,161,572	$1,823,222	

Note 1: Charged thru clearing account
Note 2: Amortized

Sources:
Column C: Average beginning and end-of-year balances per Statement J, Workpapers pp. 2-4 (Attachment A to Response to Staff DRQ 1-4)
Column D: Pre-existing accrual rates per AUS Consultants, Inc. reports
Column E: MDU proposed rates per Statement J, Workpapers pp. 2-4 (Attachment A to Response to Staff DRQ 1-4)
Column F: N.D. settlement rates per Response to Staff DRQ 1-38

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG93-011
RESPONSES TO FOURTH DATA REQUEST OF THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
DATED NOVEMBER 8, 1993

Request No. 7: For the vintages of mains that remain in service in Account 376, describe how the typical installation (or range of installations) has changed over time. Include references to the piping material, diameter and length; trench specifications; and geographic/topographic location.

Response: Since the late 1960's, plastic pipe has replaced steel pipe as the material of choice for distribution mains and service lines. Today, plastic pipe accounts for more than 90% of the pipe installed in Montana-Dakota's gas distribution systems. Plastic pipe is rated for 60 psig, which is adequate for most all of Montana-Dakota's systems.

Today, Montana-Dakota operates most of their systems at pressures higher than those used prior to 1960. Because of this, the size of the piping installed is much smaller (½" to ¾" service lines today vs. 1¼" service lines installed in the 1950's).

The trench specifications and geographic/topographic locations have not changed much since 1960.

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG93-011
RESPONSES TO FOURTH DATA REQUEST OF THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
DATED NOVEMBER 8, 1993

Request No. 8: Describe, and support with examples, how the causes of retirements may have changed over time on the MDU gas system.

Response: The causes for retirements have not changed appreciably since 1960. Montana-Dakota will replace and retire uncoated steel piping, which is without adequate cathodic protection. This type of pipe is being replaced because it is either beginning to fail or the potential for leakage is increasing. A bare pipe replacement program was developed in 1986.

Other Plant items (i.e., meters and regulators) are replaced and retired when the cost of maintenance nears that of a replacement unit.

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG93-011
RESPONSES TO EIGHTH DATA REQUEST OF THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
DATED NOVEMBER 19, 1993

Refer to the workpapers for Adjustment A.

Request No. 2: For the item labelled budget number 018, "Main replacements to comply with D.O.T. requirements":

a. What were the D.O.T. requirements for replacements?
b. What was the physical condition, size, and composition of the main replaced?

Response: a-b. In 1984 an agreement was reached with the Office of Pipeline Safety whereby Montana-Dakota would begin to replace old, uncoated steel lines rather than update them to meet current DOT requirements. These lines are being replaced with plastic lines.

Normally, DOT does not require replacement of lines, but does require maintenance measures which, for the uncoated steel lines, equals the cost of replacement with plastic lines.

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG93-011
RESPONSES TO NINTH DATA REQUEST OF THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
DATED DECEMBER 27, 1993

Request No. 1: On December 23, 1993, MDU faxed its response to Staff's data request 8-2. Provide the following in regard to that response:

c. Provide the analysis which supports the statement in Response 8-2 that, for the pipe to be replaced, "maintenance measures...equals the cost of replacement." Provide the specific replacement/maintenance cost analyses performed in support of the 1984 agreement and the 1986 program.

Response

c. The primary concern is safety and compliance with federal guidelines regarding bare pipe. There was no specific cost analysis performed regarding replacement versus maintenance at the time the program was implemented.

Montana-Dakota was aware, through leak surveys, that the bare pipe was beginning to fail and that it had to be phased out over a period of years. Given that it had to be replaced in a relatively short time period, it was obviously less costly to simply replace it than to maintain it for a few years and then replace it. In addition, cathodic protection would have been required for maintenance which, for bare pipe, accelerates the deterioration in the short-term.

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG93-011
RESPONSES TO FOURTH DATA REQUEST OF THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
DATED NOVEMBER 8, 1993

Request No. 10: Is MDU permitted to abandon any gas piping in place in any jurisdiction? (If so, explain where and under what circumstances.)

Response: Pipe is abandoned in all jurisdictions. Montana-Dakota is required to maintain records identifying the location of abandoned pipe.

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG93-011
RESPONSES TO FOURTH DATA REQUEST OF THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
DATED NOVEMBER 8, 1993

Request No. 9: Describe MDU's policies and practices for removing Distribution mains and gas Services. Explain any differences in governmental requirements among the states in which MDU provides gas service.

Response: Removal of abandoned/retired distribution mains and services is not a normal practice for Montana-Dakota. Pipe is removed when necessary, to accommodate replacement work on new installations.

Exhibit___(RGT-2)
Schedule 1
Docket No. NG04-004

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Embedded Class Cost of Service Study - Staff Allocation of Distribution Mains
Summary Report
Pro Forma 2004

Pro Forma Operating Income and Rate of Return	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Operating Revenues	58,328,990	31,198,557	18,894,011	3,888,530	3,302,175	410,008	635,709
Operating Expenses							
O&M Cost of Purchased Gas	46,083,134	22,884,908	15,624,046	3,657,655	3,235,734	179,617	501,174
Other O&M Expense	8,517,186	5,873,394	2,302,531	82,761	14,730	144,605	99,165
Total Operation & Maint. Exp.	54,600,320	28,758,302	17,926,577	3,740,416	3,250,464	324,222	600,339
Depreciation	1,842,355	1,099,972	643,299	34,883	1,346	37,722	25,133
Taxes Other Than Income Taxes	827,838	531,332	256,394	12,278	1,201	15,383	11,250
Fed. & State Inc. Taxes - Current	(960,970)	(415,817)	(435,674)	(41,047)	(50,175)	(921)	(17,336)
Deferred Income Taxes	1,012,916	474,150	346,387	89,653	92,375	37	10,314
Total Operating Expenses	57,322,459	30,447,939	18,736,983	3,836,183	3,295,211	376,443	629,700
Operating Income	1,006,531	750,618	157,028	52,347	6,964	33,565	6,009
Rate Base	19,119,950	11,391,819	6,622,592	364,074	29,764	400,001	311,700
Rate of Return	5.264%	6.589%	2.371%	14.378%	23.397%	8.391%	1.928%

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Rates of Return Earned with MDU- Proposed Class Increases -- Staff Allocation of Distribution Mains
Pro Forma 2004

	South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1. Rate Base as filed	19,119,950	11,391,819	6,622,592	364,074	29,764	400,001	311,700
2. Operating income before increase	1,006,531	750,618	157,028	52,347	6,964	33,565	6,009
3. MDU proposed revenue increase	1,281,417	896,242	378,740	0	0	0	6,435
4. Inc. and Rev. Tax on increase @ 35.15%	450,418	315,029	133,127	0	0	0	2,262
5. Additional income produced by increase	$830,999	$581,213	$245,613	$0	$0	$0	$4,173
6. Operating income at MDU proposed rates	$1,837,530	$1,331,831	$402,641	$52,347	$6,964	$33,565	$10,182
7. Rate of return at proposed rates	9.61%	11.69%	6.08%	14.38%	23.40%	8.39%	3.27%

Sources:
Lines 1,2: Exhibit___(RGT-2), Schedule 1
Line 3: MDU Statement O, page 1

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Rates of Return Earned with MDU- Proposed Class Increases - MDU Allocation of Distribution Mains
Pro Forma 2004

(A)	South Dakota (B)	Residential (C)	Firm General (D)	Firm Contract (E)	Air Force (F)	Small Interruptible (G)	Large Interruptible (H)
1. Rate base as filed	$19,119,933	$12,597,739	$5,674,980	$238,124	$29,764	$348,544	$230,782
2. Operating income before increase	1,006,532	568,917	299,809	71,321	6,964	41,320	18,201
3. MDU proposed revenue increase	1,281,417	896,242	378,740	0	0	0	6,435
4. Inc. and rev. tax on increase @ 35.15%	450,418	315,029	133,127	0	0	0	2,262
5. Additional income produced by increase	$830,999	$581,213	$245,613	$0	$0	$0	$4,173
6. Operating income at MDU proposed rates	$1,837,531	$1,150,130	$545,422	$71,321	$6,964	$41,320	$22,374
7. Rate of return at proposed rates	9.61%	9.13%	9.61%	29.95%	23.40%	11.86%	9.69%

Sources:
Lines 1,2: MDU Statement N-1, page 4
Line 3: MDU Statement O, page 1

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Spread of Proposed Rate Increase-- Staff Allocation of Distribution Mains
Pro Forma 2004

(A)	South Dakota (B)	Residential (C)	Firm General (D)	Firm Contract (E)	Air Force (F)	Small Interruptible (G)	Large Interruptible (H)
1. Rate Base as filed	$19,119,950	$11,391,819	$6,622,592	$364,074	$29,764	$400,001	$311,700
2. Operating income before increase	1,006,531	750,618	157,028	52,347	6,964	33,565	6,009
3. MDU proposed revenue increase	**$1,281,417**	**$896,242**	**$378,740**	**$0**	**$0**	**$0**	**$6,435**
4. Income and Revenue taxes @ 35.15%	450,418	315,029	133,127	0	0	0	2,262
5. Additional income produced by increase	$830,999	$581,213	$245,613	$0	$0	$0	$4,173
6. Operating income at MDU proposed rates	$1,837,530	$1,331,831	$402,641	$52,347	$6,964	$33,565	$10,182
7. Rate of return at proposed rates	9.61%	11.69%	6.08%	14.38%	23.40%	8.39%	3.27%
Increase deficient returns to system objective return							
8. Additional return @ 9.61%			$233,777			$4,880	$19,762
9. Income and Revenue taxes @35.15%			126,712				
10. Additional increase			360,490			7,525	30,473
11. Total increase	1,281,417	497,754	739,230			7,525	36,908
Resulting Rate of return earned							
12. Adjusted increase	**$1,281,417**	**$497,754**	**$739,230**	**$0**	**$0**	**$7,525**	**$36,908**
13. Inc. and Rev. Tax on increase @ 35.15%	450,418	174,961	259,839	0	0	2,645	12,973
14. Additional income produced by increase	$830,999	$322,793	$479,391	$0	$0	$4,880	$23,935
15. Operating income at MDU proposed rates	$1,837,530	$1,073,411	$636,419	$52,347	$6,964	$38,445	$29,944
16. Rate of return with adjusted increase	9.61%	9.42%	9.61%	14.38%	23.40%	9.61%	9.61%
Impacts							
17. Total revenue at existing rates	$58,064,657	$31,053,318	$18,818,121	$3,882,454	$3,272,406	$405,998	$632,360
18. Percent increase - MDU	2.21%	2.89%	2.01%	0.00%	0.00%	0.00%	1.02%
19. - Staff	2.21%	1.60%	3.93%	0.00%	0.00%	1.85%	5.84%

Source: Lines 1 and 2: Schedule 1
Lines 3 and 17: Statement O, Schedule O-1, page 1

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Spread of Proposed Rate Increase-- Staff Allocation of Distribution Mains
Pro Forma 2004

	South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible	Combined Classes w/ Deficiencies
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1. Rate Base as filed	$19,119,950	$11,391,819	$6,622,592	$364,074	$29,764	$400,001	$311,700	$7,334,293
2. Operating income before increase	1,006,531	750,618	157,028	52,347	6,964	33,565	6,009	$196,602
3. MDU proposed revenue increase	**$1,281,417**	**$896,242**	**$378,740**	**$0**	**$0**	**$0**	**$6,435**	$385,175
4. Income and Revenue taxes @ 35.15%	450,418	315,029	133,127	0	0	0	2,262	$135,389
5. Additional income produced by increase	$830,999	$581,213	$245,613	$0	$0	$0	$4,173	$249,786
6. Operating income at MDU proposed rates	$1,837,530	$1,331,831	$402,641	$52,347	$6,964	$33,565	$10,182	$446,388
7. Rate of return at proposed rates	9.61%	11.69%	6.08%	14.38%	23.40%	8.39%	3.27%	6.09%
Increase deficient returns to system objective return								
8. Additional return @ 9.61% or 9.32%		($236,950)	$214,572			$3,720	$18,858	
9. Income and Revenue taxes @35.15%		(128,432)	116,302					
10. Additional increase		(365,381)	330,874			5,736	29,079	
11. Total increase	1,281,417	530,861	709,614			5,736	35,514	
Resulting Rate of return earned								
12. Adjusted increase	**$1,281,417**	**$530,861**	**$709,614**	**$0**	**$0**	**$5,736**	**$35,514**	
13. Inc. and Rev. Tax on increase @ 35.15%	450,418	186,598	249,429	0	0	2,016	12,483	
14. Additional income produced by increase	$830,999	$344,263	$460,185	$0	$0	$3,720	$23,031	
15. Operating income at MDU proposed rates	$1,837,530	$1,094,881	$617,213	$52,347	$6,964	$37,285	$29,040	$683,338
16. Rate of return with adjusted increase	9.61%	9.61%	9.32%	14.38%	23.40%	9.32%	9.32%	9.32%
Impacts								
17. Total revenue at existing rates	$58,064,657	$31,053,318	$18,818,121	$3,882,454	$3,272,406	$405,998	$632,360	
18. Percent increase - MDU	2.21%	2.89%	2.01%	0.00%	0.00%	0.00%	1.02%	
19. - Staff	2.21%	1.71%	3.77%	0.00%	0.00%	1.41%	5.62%	

Source: Lines 1 and 2: Schedule 1
Lines 3 and 17: Statement O, Schedule O-1, page 1

MONTANA-DAKOTA UTILITIES CO.
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF
FIRST DATA REQUEST
DATED AUGUST 6, 2004
DOCKET NO. NG04-004

Exhibit No.___(RGT-2)
Schedule 4
Page 1 of 3
Docket No. NG04-004

Request No. 1-42 Class Cost of Service Study

Explain how and why Account 376 - Mains was separated into two components for allocation on the basis of Average Customers and Peak demand (see Schedule N–2, page 1).

Response:

Gas distribution mains were allocated based on customers and peak-day demand in order to recognize the nature of the distribution system, which was designed based on the number of customers to be served and the peak-day requirements of those customers. Based on the Company's study of the zero or minimum size main necessary to connect a customer to the system, 36% of the mains investment is related to the customer component with the reminder of 64% related to the 2-day peak at distribution.

MONTANA-DAKOTA UTILITIES CO.
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF
INITIAL DATA REQUEST
DATED JANUARY 16, 2003
DOCKET NO. NG02-011

Exhibit No.___(RGT-2)
Schedule 4
Page 2 of 3
Docket No. NG04-004

Request No. 24 Class Cost of Service Study

Explain how and why Account 376 - Mains was separated into two components for allocation on the basis of Numbers of Customers and Peak demand (see Statement N, Part B, page 1).

Response:
Gas distribution mains were allocated based on customers and peak-day demand in order to recognize the nature of the distribution system which was designed based on the number of customers to be served and the peak-day requirements of those customers. Based on the Company's study of the zero or minimum size main necessary to connect a customer to the system, 36% of the mains investment is related to the customer component with the reminder of 64% related to the 2-day peak at distribution. Please see Attachment A.

Response No. 24
Attachment A
Page 1 of 1

MONTANA-DAKOTA UTILITIES CO.
GAS MAIN ANALYSIS
DECEMBER 31, 2001

STEEL MAIN	MILES OF MAIN	FOOTAGE	PLANT INVESTMENT	COST/FOOT
0.50	0.185	977	$721.66	0.73865
0.75	16.929	89,385	84,781.16	0.94849
1.00	30.46	160,829	284,166.42	1.76689
1.25	355.916	1,879,236	2,602,684.68	1.38497
1.50	4.596	24,267	27,702.01	1.14155
2.00	882.537	4,659,795	11,773,066.43	2.52652
2.50	3.258	17,202	23,535.47	1.36818
3.00	233.308	1,231,866	6,281,538.69	5.09921
4.00	454.269	2,398,540	15,270,696.25	6.36666
5.00	5.245	27,694	105,767.78	3.81916
6.00	149.2	787,776	6,939,712.46	8.80925
7.00	0.844	4,456	27,659.20	6.20718
8.00	106.56	562,637	5,142,951.83	9.14080
10.00	28.527	150,623	977,298.15	6.48837
12.00	29.406	155,264	793,678.02	5.11180
Total Steel Main	2,301.24	12,150,547	50,335,960.21	
PLASTIC MAIN				
0.50	0.223	1,177	1,018.34	0.86520
0.75	30.717	162,186	152,438.26	0.93990
1.00	11.735	61,961	122,749.62	1.98108
1.25	481.209	2,540,784	2,175,339.43	0.85617
2.00	1256.711	6,635,434	15,037,964.02	2.26631
3.00	78.766	415,884	1,480,123.82	3.55898
4.00	279.125	1,473,780	7,224,367.26	4.90193
6.00	23.545	124,318	1,763,536.79	14.18569
8-Jan	0.617	3,258	40,655.43	12.47865
Total Plastic Main	2,162.65	11,418,782	$27,998,192.97	
TOTAL	**4,463.89**	**23,569,329**	**$78,334,153.18**	

Intercept:	
Steel Main	1.494891385
Plastice Main	-0.757314127
Plastic:	
Minimum Size	0.86520
Total Feet	11,418,782
Customer Component	9,879,526
Steel:	
Zero Intercept	$1.49489
Feet	12,150,547
Customer Component	18,163,731
Total Customer Component	28,043,257
Distribution Mains @ 12/01	78,334,153
Customer Component	35.800%

Exhibit No.___(RGT-2)
Schedule 4
Page 3 of 3
Docket No. NG04-004

Exhibit___(RGT-3)
Docket No. NG04-004

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Customer Cost Analysis
Pro Forma 2004

Item	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
(A)	(B)	(C)	(D)	(E)	(F)	(G)
Customer-related plant in service						
1. Service Regulators	$530,086	$289,579	$1,425	$0	$32,437	$9,125
2. Indust. Meas. & Reg. Sta. Eqpt.	0	0	0	0	8,699	54,730
3. Services	3,507,756	1,883,478	9,432	0	157,388	0
4. Meters	3,889,660	2,088,540	$10,459	0	174,524	0
5. Total customer plant in service	$7,927,502	$4,261,597	$21,316	$0	$373,048	$63,855
6. Accumulated depreciation	(5,028,027)	(2,701,773)	(13,520)	0	(232,003)	(22,061)
7. Accumulated deferred income taxes	(329,816)	(177,299)	(887)	0	(15,520)	(2,657)
8. Accumulated investment tax credits	(3,638)	(1,955)	(9)	0	(171)	(29)
9. Customer advances for construction	(21,248)	(31,508)	(1)	0	0	0
10. Customer-related net plant	$2,544,773	$1,349,062	$6,899	$0	$125,354	$39,108
Customer-related cost of service						
11. Rate of return @ 9.613%	244,629	129,685	663	0	12,050	3,759
12. Income taxes on return	77,845	41,268	211	0	3,835	1,196
Operating expenses						
13. Services	96,009	51,552	258	0	4,308	0
14. Measuring stations - Industrial					963	6,060
15. Meters and house regulators	195,374	105,124	525	0	9,149	403
16. Customer installations	257,637	138,337	693	0	11,560	0
Maintenance expenses						
17. Measuring stations - Industrial					835	5,254
18. Services	5,368	2,882	14	0	241	0
19. Meters and house regulators	30,826	16,586	83	0	1,443	64
20. Customer accounts	91,445	12,275	2	2	89	22
21. Meter reading	196,602	105,565	529	0	8,821	4,758
22. Customer records & collection	711,335	95,487	19	19	694	169
23. Miscellaneous customer accounts	69,902	9,383	2	2	68	17
24. Customer service & information	43,897	5,893	1	1	43	10
25. Employee pensions and benefits	360,654	117,636	473	0	8,401	3,646
26. Depreciation expense	399,094	214,411	1,073	0	18,279	1,263
27. Property taxes	59,081	31,906	166	0	2,782	814
28. Customer-related cost of service	$2,839,698	$1,077,990	$4,712	$24	$83,561	$27,435
29. Number of annual bills	455,196	61,104	12	12	444	108
30. Customer cost per bill	**$6.24**	**$17.64**	$392.67	$2.00	$188.20	**$254.03**
31. Customer cost per day	**$0.205**	**$0.580**				
32. Present rate	**$0.25**	**$0.33 or .66**				**$150 or 200**
33. Proposed rate	**$0.26**	**$0.35 or .70**				**$175 or 225**

Source: Exhibit___(RGT-2) class cost of service study detail

CERTIFICATE OF SERVICE

I hereby certify that copies of testimony of David A. Jacobson, Michele M. Farris, Martin C. Bettmann, Keith A. Senger, Basil L. Copeland, Jr. and Robert G. Towers were served on the following by mailing the same to them by United States Post Office First Class Mail, postage thereon prepaid, at the addresses shown below on this the 19th day of October, 2004.

Karen E. Cremer

Karen E. Cremer
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	ORDER CANCELLING HEARING NG04-004

On June 7, 2004, Montana-Dakota Utilities Co. (MDU), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in its Black Hills service territory. The application seeks an increase in rates in the approximate amount of $1,281,417 or approximately 2.2%. On June 22, 2004, the Commission suspended the proposed schedule of rates for 90 days beyond June 7, 2004.

At its regularly scheduled meeting of June 22, 2004, the Commission found that pursuant to SDCL 49-1A-8, MDU shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 9, 2004. On July 15, 2004, Commission Staff advised the Commission that the suspension should have been for 90 days beyond July 7, 2004. On July 20, 2004, pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by MDU for 90 days beyond July 7, 2004.

The Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26 and 49-34A, specifically 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-17, 49-34A-19, 49-34A-21.

By order dated October 4, 2004, a hearing was scheduled for November 4, 2004, beginning at 9:00 A.M. and November 5, 2004, beginning at 8:30 A.M., in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota. On October 28, 2004, the Commission was informed that Commission Staff and MDU had reached a settlement agreement, so therefore the hearing is cancelled. It is therefore

ORDERED, that the hearing scheduled for November 4 and 5, 2004, is cancelled.

Dated at Pierre, South Dakota, this 28th day of October, 2004.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 10/28/04

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

ROBERT K. SAHR, Chairman

GARY HANSON, Commissioner

JAMES A. BURG, Commissioner

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November 15, 2004

RECEIVED
NOV 15 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

HAND DELIVERED

Pam Bonrud
Executive Secretary
Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

RE: In The Matter Of The Application Of Montana-Dakota Utilities Co. For Authority To Increase Natural Gas Rates In South Dakota
PUC Docket No.: NG04-004
Our file: 0069

Dear Pam:

Enclosed please find an original and ten copies of a Joint Motion for Approval of Settlement Stipulation NG04-004 and Settlement Stipulation in the above referenced docket.

Very truly yours.

MAY, ADAM, GERDES & THOMPSON LLP

BRETT M. KOENECKE

BMK:njh

Enclosures

cc: Don Ball

RECEIVED
NOV 15 2004
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE NATURAL GAS RATES IN SOUTH DAKOTA.	))))	**JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION NG04-004**

Montana-Dakota Utilities Co. (Montana-Dakota) and the Staff of the South Dakota Public Utilities (Commission Staff), collectively referred to as Parties, hereby file the above-referenced Motion and Settlement Stipulation with the South Dakota Public Utilities Commission (Commission). The Parties propose that the Commission adopt the Settlement Stipulation as the settlement and resolution of all the issues in this proceeding. In support of this Mouton, the Parties submit as follows:

1. This Motion is made pursuant to ARSD 20:10:01:19.

2. The Settlement Stipulation resolves all of the issues in Docket No. NG04-004.

3. The Settlement Stipulation represents the conclusion of the undersigned parties that it is in the best interests of the Parties and the general public to reach a negotiated settlement of specific issues in this case and that the terms of the Settlement Stipulation agreed upon are just, fair, and reasonable, and consistent with South Dakota law.

For the foregoing reasons, the undersigned parties jointly request the Commission to adopt the attached Settlement Stipulation without modification for the purpose of resolving the specific issues for use in determining the revenue requirement of Montana-Dakota Utilities in Docket No. NG04-004.

Montana-Dakota Utilities Co.

BY: _____

Brett Koenecke
Attorney
May, Adam, Gerdes & Thompson, LLP
503 S. Pierre Street
PO Box 160
Pierre, SD 57501

DATED: 11/15/04

South Dakota Public Utilities Commission

BY: Karen E. Cremer

Karen E. Cremer
Attorney
State Capital Building
500 E. Capitol
Pierre, SD 57501

DATED: 11/16/04

RECEIVED
NOV 15 2004
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE NATURAL GAS RATES IN SOUTH DAKOTA	)	DOCKET NO. NG04-004

I. SETTLEMENT STIPULATION

On June 7, 2004, Montana-Dakota Utilities Co. ("Montana-Dakota") filed with the South Dakota Public Utilities Commission ("Commission") an application for approval to increase rates for natural gas service in the State of South Dakota for its Black Hills system. Montana-Dakota proposed an overall increase of $1,281,417. The Staff of the Commission ("Commission Staff") on October 19, 2004, filed its direct testimony supporting an overall increase for Montana-Dakota of $210,448.

The Commission Staff and Montana-Dakota (jointly the "Parties") held several negotiating sessions in an effort to arrive at a jointly acceptable resolution of this matter. As a result of the sessions, the Parties have been able to resolve all issues in this proceeding and have entered into this Settlement Stipulation ("Stipulation"), which, if accepted and ordered by the Commission, will determine rates to result from this proceeding.

II. PURPOSE

This Stipulation has been prepared and executed by the Parties for the sole purpose of resolving Docket No. NG04-004. The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Settlement Agreement, should not be viewed as precedent setting. In consideration of the mutual promises hereinafter set forth, the Parties agree as follows:

1. Upon execution of this Stipulation, the Parties shall immediately file this Stipulation with the Commission together with a joint motion requesting that the Commission issue an order approving this Stipulation in its entirety without condition or modification.

2. This Stipulation includes all terms of settlement and is submitted with the condition that in the event the Commission imposes any changes in or conditions to this Stipulation which are unacceptable to any party, this Stipulation shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding nor be used for any other purpose.

3. This Stipulation shall become binding upon execution by the Parties, provided however, that if this Stipulation does not become effective in accordance with Paragraph 2 above, it shall be null, void and privileged. This Stipulation is intended to relate only to the specific matters referred to herein; no party waives any claim or right which it may otherwise have with respect to any matter not

expressly provided for herein; no party shall be deemed to have approved, accepted, agreed or consented to any rate making principle, or any method of cost of service determination, or any method of cost allocation underlying the provisions of this Stipulation, or be prejudiced or bound thereby in any other current or future proceeding before the Commission. No party or representative thereof shall directly or indirectly refer to this Stipulation or that part of any order of the Commission referring to this Stipulation as precedent in any other current or future rate proceeding before the Commission.

4. The Parties to this proceeding stipulate that all prefiled testimony, exhibits, and workpapers be made a part of the record in this proceeding. The Parties understand that if this matter had not been settled, Montana-Dakota would have filed rebuttal testimony and the Commission Staff would have responded to certain of the positions contained in Montana-Dakota's rebuttal testimony.

5. It is understood that Commission Staff enters into this Stipulation for the benefit of Montana-Dakota's South Dakota customers affected by this docket.

III. ELEMENTS OF THE SETTLEMENT STIPULATION

1. Revenue Requirement

The Parties agree that Montana-Dakota's attached rate schedules are designed to produce annual increases in base rate levels (excluding purchased gas cost adjustment and sales taxes) of $669,549 annually for retail natural gas service in the Company's Black Hills service area in the State of South Dakota. The parties agree to an overall rate of return of 8.917%.

2. Tariffs

The increase will be allocated on an equal percentage basis to the Residential, Firm General Service and Large Interruptible rate classes resulting in an increase of 1.6% to each of the affected rate classes. The Tariffs reflect the following basic service charges with the remainder of the applicable revenue increase collected through the Distribution Delivery Charges:

Rate Class	Base Rate
Residential	$0.25 per day
Firm General	
Meters < 500 cubic ft./hour	$0.35 per day
Meters > 500 cubic ft./hour	$0.70 per day
Air Force	$95.00 per month
Small Interruptible Sales	$50.00 per month
Small Interruptible Transport	$125.00 per month
Large Interruptible Sales	$175.00 per month
Large Interruptible Transport	$225.00 per month

3. Implementation of Rates

The revised rate schedules shall be implemented with service rendered on and after December 1, 2004, with bills prorated so that usage prior to December 1, 2004 is billed at the previous rates and usage on and after December 1, 2004, is billed at the new rates.

4. Conclusion

This Stipulation is entered into this 15 day of November, 2004.

Montana-Dakota Utilities Co.

BY: _____

South Dakota Public Utilities Commission

BY: Karen E. Cremer

Mr. Brett M. Koenecke
Attorney
May, Adam, Gerdes and Thompson
503 South Pierre Street
P.O. Box 160
Pierre, SD 57501

DATED: 11/15/04

Karen E. Cremer
Attorney
State Capitol Building
500 East Capitol Building
Pierre, SD 57501-5070

DATED: 11/16/04

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 1
1st Revised Sheet No. 1
Canceling Original Sheet No. 1

TABLE OF CONTENTS

Designation	Title	Sheet No.
Section No. 1	Table of Contents	1
Section No. 2	Preliminary Statement	1
Section No. 3	Rate Schedules	
	Rate Summary Sheet	1
Rate 60	Residential Gas Service	2
	Reserved for Future Use	3-4
Rate 64	Ellsworth Air Force Base	5
	Reserved for Future Use	6
Rate 66	East River Natural Gas System General Services	7
	Reserved for Future Use	8-10
Rate 70	Firm General Gas Service	11
Rate 71	Small Interruptible General Gas Service	12
Rate 72	Optional Seasonal General Gas Service	13
	Reserved for Future Use	14-21
Rate 81 and 82	Transportation Service	22
	Reserved for Future Use	23-25
Rate 85	Large Interruptible General Gas Service	26
	Reserved for Future Use	27
Rate 87	Distribution Delivery Stabilization Mechanism	28
Rate 88	Purchased Gas Cost Adjustment	29
Rate 89	East River Natural Gas System Purchase Gas Cost Adjustment	30
Section No. 4	List of Contracts with Deviations	1
Section No. 5	Rules	
Rate 100	General Provisions	1
	Reserved for Future Use	2
Rate 102	Residential Rate for Regular Employees	3
	Reserved for Future Use	4-18
Rate 119	Interruptible Gas Service Extension Policy	19
Rate 120	Firm Gas Service Extension Policy	20
	Reserved for Future Use	21-23

Date Filed: June 7, 2004
Effective Date: Service Rendered on and after December 1, 2004

Issued By: Donald R. Ball
Asst. Vice President-Regulatory Affairs

Docket No.: NG04-004

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TABLE OF CONTENTS

Rate 124	New Installation, Replacement, Relocation and Repair of Gas Service Lines	24
	Reserved for Future Use	25-33
Rate 134	Rules and Policies for Implementing Master Metering Restrictions	34
Section No. 6	Sample Forms	
	Consumer's Deposit Receipt	1
	New Customer Application Card	2
	Gas Meter Order	3
	Standard Customer Bill	4
	Disconnect Notice	5
	Application for Interruptible Natural Gas Service	6
	Customer Information Booklet	7
	Discontinuance Notices for Causes Other Than Nonpayment of Bills	8
	Third Party Notice	9
	Deferred Installment Agreement Form	10
	Agreement by Property Owner or Agent to Pay Utility Bills During Periods When Property is Unoccupied	11
	Reserved for Future Use	12
	Guarantee of Payment for Natural Gas and/or Electric Service by a Second Party in Lieu of a Deposit	13
	Deposit Warning Letter	14
	Deposit Request	15
	Final Notice Prior to Disconnect	16
	Interruptible General Gas Service Agreement	17
	Request for Firm Natural Gas Sales Service	18
	Gas Transportation Agreement	19
	Customers Agreement for Gas Extension	20
	Gas Service Order	21
	Facilities Relocation Agreement	22
	Warning Notice	23
	Temporary Construction Heat Agreement	24

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule - SDPUC Volume No. 2

Section No. 3
9th Revised Sheet No. 1
Canceling 8th Revised Sheet No. 1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	PGA Items	Total Rate/ Dk
Residential Rate 60	2	$0.25 per day	$1.571	$8.571	$10.142
Ellsworth Air Force Base Rate 64	5	$95.00 per month	$0.062	$6.970	$7.032
East River Gas System Rate 66	7				
Meters rated < 500 cubic feet		$2.00 per month			
Meters rated > 500 cubic feet		$4.00 per month	$1.761	$8.632	$10.393
Firm General Service Rate 70	11				
Meters rated < 500 cubic feet		$0.35 per day			
Meters rated > 500 cubic feet		$0.70 per day	$1.175	$8.571	$9.746
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	12	$50.00 per month	$0.453	$8.571	$9.024
Optional Seasonal Gas					
Service Rate 72	13				
Meters rated < 500 cubic feet		$0.35 per day			
Meters rated > 500 cubic feet		$0.70 per day			
Winter Gas Usage			$1.175	$9.016	$10.191
Summer Gas Usage			$1.175	$7.428	$8.603
Transportation Service	22				
Small Interruptible Rate 81		$125.00 per month			
Maximum			$0.453		
Minimum			$0.131		
Fuel Charge				$0.092	
Large Interruptible Rate 82		$225.00 per month			
Maximum			$0.187		
Minimum			$0.090		
Fuel Charge				$0.077	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	26	$175.00 per month	$0.187	$7.819	$8.006

Date Filed: November 12, 2004

Effective Date: Service Rendered on and after December 1, 2004

Issued By: Donald R. Ball
Asst. Vice President - Regulatory Affairs

Docket No.: NG04-004

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
1st Revised Sheet No. 2
Canceling Original Sheet No. 2

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served, except for those communities set forth on Rate 66, for all domestic uses. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	$0.25 per day
Distribution Delivery Charge:	$1.571 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

General Terms and Conditions:

RULES - The foregoing schedule is subject to Rates 100 through 134 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
1st Revised Sheet No. 11
Canceling Original Sheet No. 11

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served, except for those communities set forth on Rate 66, for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.35 per day
For customers with meters rated over 500 cubic feet per hour	$0.70 per day
Distribution Delivery Charge:	$1.175 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
1st Revised Sheet No. 13
Canceling Original Sheet No. 13

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served, except for those communities set forth on Rate 66, for customers otherwise qualifying for service under Firm General Gas Service Rate 70. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.35 per day
For customers with meters rated over 500 cubic feet per hour	$0.70 per day
Distribution Delivery Charge:	$1.175 per dk
Cost of Gas:	
Winter – Bills rendered October 1 through May 31	Determined Monthly – See Rate Summary Sheet for Current Rate
Summer – Bills rendered June 1 through September 30	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

TRANSPORTATION SERVICE Rates 81 and 82

Rate:

Basic Service Charge:

Rate 81	$125.00 per month 1/
Rate 82	$225.00 per month 2/

1/ In the event customer takes service through one meter under both Rates 71 and 81, the base rate under Rate 81 shall be waived.

2/ In the event customer takes service through one meter under both Rates 85 and 82, the base rate under Rate 82 shall be waived.

Under Rates 81 or 82 customer shall pay a negotiated rate not more than the maximum rate or less than the minimum rate specified below. (The per dk charge is applicable to all dk of natural gas transported under the terms of this rate.)

	Rate 81	Rate 82
Maximum Rate per dk	$0.453	$0.187
Minimum Rate per dk	$0.131	$0.090
Balancing Charge per dk	$0.300	$0.300

Fuel Charge:

Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See Rate Summary Sheet for currently effective charge.

GENERAL TERMS AND CONDITIONS:

1. CRITERIA FOR SERVICE – In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. The customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
1st Revised Sheet No. 26
Canceling Original Sheet No. 26

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served, except those communities set forth on Rate 66, for all interruptible general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will exceed 40,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement. The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

This rate schedule shall not apply for service to U. S. Government installations, which are covered by separate special contracts.

Rate:

Basic Service Charge:	$175.00 per month
Distribution Delivery Charge:	
Maximum Rate	$0.187 per dk
Minimum Rate	$0.090 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
1st Revised Sheet No. 1
Canceling Original Sheet No. 1

TABLE OF CONTENTS
GENERAL PROVISIONS Rate 100

Title		Page No.
I.	Purpose	3
II.	Definitions	3-5
III.	Customer Obligations	
	1. Application for Service	5
	2. Input Rating	5
	3. Access to Customer's Premises	6
	4. Company Property	6
	5. Interference with Company Property	6
	6. Relocated Lines	6
	7. Notification of Leaks	6
	8. Termination of Gas Service	6
	9. Reporting Requirement	6
	10. Quality of Gas	7
IV.	Liability	
	1. Continuity of Service	7
	2. Customer's Equipment	7
	3. Company Equipment and Use of Service	7
	4. Indemnification	7
	5. Force Majeure	7-8
V.	General Terms and Conditions	
	1. Agreement	9
	2. Rate Options	9
	3. Rules for Application of Gas Service	9-10
	4. Dispatching	10
	5. Rules Covering Gas Service to Manufactured Homes	10
	6. Consumer Deposits	10-11
	7. Metering and Measurement	12
	8. Measurement Unit for Billing Purposes	12
	9. Unit of Volume for Measurement	12-13
	10. Priority of Service & Allocation of Capacity	13-14

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 5
1st Revised Sheet No. 1.1
Canceling Original Sheet No. 1.1

TABLE OF CONTENTS
GENERAL PROVISIONS Rate 100

Title		Page No.
V.	General Terms and Conditions (cont.)	
	11. Late Payment	14
	12. Returned Check Charge	14
	13. Tax Clause	14
	14. Utility Customer Services	14-15
	15. Utility Services Performed after Normal Business Hours	15
	16. Notice to Discontinue Gas Service	15
	17. Installing Temporary Metering Facilities or Service	16
	18. Reconnection Fee for Seasonal or Temporary Customers	16
	19. Discontinuance of Service for Nonpayment of Bills	16
	20. Discontinuance of Service for Causes other than Nonpayment of Bills	17
	21. Unauthorized Use of Service	18-19
	22. Gas Meter Test by Customer Request	19-20
	23. Additional Rates Identifying Special Provisions	20

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

I. PURPOSE:

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other accepted standards and practices not covered herein. They are intended to ensure adequate service to the public and protect the Company from unreasonable demands.

The Company undertakes to furnish service subject to the rules and regulations of the Public Utilities Commission of South Dakota and as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. DEFINITIONS:

The following terms used in this tariff shall have the following meanings, unless otherwise indicated:

AGENT – The party authorized by the transportation service customer to act on that customer's behalf.

APPLICANT – A customer requesting Company to provide service.

COMMISSION – Public Utilities Commission of the State of South Dakota.

COMPANY – Montana-Dakota Utilities Co. (Montana-Dakota)

COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the customer's convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.

CURTAILMENT – A reduction of transportation or retail natural gas service deemed necessary by the Company. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by the Company at one location and at one point of delivery unless otherwise expressly provided in these rules or in a rate schedule.

DELIVERY POINT – The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of Company's meter(s) located on customer's premises.

GAS DAY – Means a period of twenty-four consecutive hours, beginning and ending at 9:00 A.M. Central Clock Time.

HOUSEHOLD – A family or a group of people who live together.

INDEBTED HOUSEHOLD – A group of people living together among whom there is one who is indebted to a gas utility for service provided previously to the residence for which service is now sought.

INTERRUPTION – A cessation of transportation or retail natural gas service deemed necessary by the Company.

NOMINATION – The daily dk volume of natural gas requested by customer for transportation and delivery to customer at the delivery point during a gas day.

PIPELINE – The transmission company(s) delivering natural gas into company's system.

RATE – Shall mean and include every compensation, charge, fare, toll, rental and classification, or any of them, demanded, observed, charged or collected by the Company for any service, product, or commodity, offered by the Company to the public. This includes any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

RECEIPT POINT – The intertie between the Company and the interconnecting pipeline(s) at which point the Company assumes custody of the gas being transported.

SHIPPER – The party with whom the Pipeline has entered into a service agreement with in order to provide transportation services.

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE – A customer desiring gas service must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. The Company may refuse an applicant or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any person who uses gas service in the absence of an application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

   Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

   Any customer may be asked to make a deposit as required. Pursuant to Rate 100 § V.6.

2. INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates and pressure required for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at the Company's sole discretion, the Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will insure that such equipment will conform to the Company's ability to adequately serve such installations with gas.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

3. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

4. COMPANY PROPERTY – The customers shall exercise reasonable diligence in protecting the Company's property on their premises, and shall be liable to the Company in case of loss or damage caused by their negligence or that of their employees.

5. INTERFERENCE WITH COMPANY PROPERTY – The customer shall not disconnect, change connections, make connections or otherwise interfere with the Company's meters or other property or permit same to be done by other than the Company's authorized employees or representatives.

6. RELOCATED LINES – Where Company facilities are located on a public or private utility easement and customer erects or installs a building, over gas facilities (Company-owned main, Company-owned service line or customer-owned service line) the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

7. NOTIFICATION OF LEAKS – The customer shall immediately notify the Company at its office of any escape of gas in or about the customer's premises.

8. TERMINATION OF GAS SERVICE – All customers are required to notify the Company, to prevent their liability for service used by succeeding tenants, when vacating their premises. Upon receipt of such notice, the Company will read the meter and further liability for service used on the part of the vacating customer will cease.

9. REPORTING REQUIREMENTS – Customer shall furnish the Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

10. QUALITY OF GAS – The gas tendered to the Company shall conform to the applicable quality specifications of the transporting pipeline's tariff.

IV. LIABILITY:

1. CONTINUITY OF SERVICE – The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same except when such loss, injury, death or damage results from the negligence of the Company.

2. CUSTOMER'S EQUIPMENT – Neither by inspection or non-rejection, nor in any other way does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer or leased by the customer from third parties.

3. COMPANY EQUIPMENT AND USE OF SERVICE – The Company will not be liable for any loss, injury, death or damage resulting in any way from the supply or use of gas or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold the Company harmless from any and all injury, death, loss or damage resulting from customer's negligent or wrongful acts under and during the term of service. The Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from the Company's negligent or wrongful acts under and during the term of service.

5. FORCE MAJEURE – In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be

suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of customer's gas are destroyed while in the Company's possession by an event of force majeure, the obligations of the parties shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or the Company, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

V. GENERAL TERMS AND CONDITIONS:

1. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for any service.

2. RATE OPTIONS – Where more than one rate schedule is available for the same class of service, the Company will assist the customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in 12 months unless there is a material change in the customer's load which alters the availability and/or applicability of such rate(s), or unless a change becomes necessary as a result of an order issued by the Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

3. RULES FOR APPLICATION OF GAS SERVICE:
   a. Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, or for the producing operations of a farm or ranch, may be served on the residential rate.

   b. Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty parlors, master metered apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site (this is not an all-inclusive list).

c. The definitions above are based upon the supply of service to an entire premise through a single delivery and metering point. Separate supply for the same customer at other points of consumption may be separately metered and billed.

d. If separate metering is not practical for a single unit (one premise) that is using gas for both domestic purposes and for conducting business (or for nonresidential purposes as defined herein), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the customer's total connected load.

e. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the Nonresidential rates.

4. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by the Company to facilitate transportation service. The Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES – The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Home Construction and Safety Standards) Subpart G and H which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities. This information is available at Montana-Dakota Utilities Co.'s offices.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission rules.

a. The amount of such deposit shall not exceed one-sixth of the estimated annual bill. If a customer has no deposit or one which is inadequate in comparison with his recent bills for service the Company may collect an additional amount in order to bring the total deposit up to the foregoing standard. Should a customer be unable to pay the full amount of the deposit, the Company shall accept payment of the deposit in reasonable installments not to exceed four months.

b. The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall automatically terminate after the customer has established credit that would result in return of a deposit or at the guarantor's request upon sixty days written notice to the Company. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

c. The customer may, in lieu of a deposit, be placed on an early payment list whereby customer shall pay the service bill within a minimum of five working days. However for early payment, early disconnection shall be proper when a customer fails to pay the service bill within a minimum of five working days.

   A deposit shall earn interest at the rate of 7% per year for such period as the customer receives service. Interest shall be credited to the customer's account annually during the month of December.

   Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for 12 months, provided prompt payment record, as defined in the Commission rules, has been established.

7. METERING AND MEASUREMENT:
   a. The Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. The Company will test meters in accordance with applicable state utility rules and regulations.

   b. Transportation customers agree to provide the cost of the installation of remote data acquisition equipment to the Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the application of a thermal factor to the volumes metered. This thermal factor consists of:

   a. An altitude adjustment factor used to convert metered volumes at local sales base pressure to a standard pressure base of 14.73 psia, and

   b. A Btu adjustment factor used to reflect the heating value of the gas delivered.

9. UNIT OF VOLUME FOR MEASUREMENT – The unit of volume for purpose of measurement shall be one (1) cubic foot of gas at either local sales base pressure or 14.73 psia, as appropriate, and at a temperature base of 60 degrees Fahrenheit (60° F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where

gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AGA-3/NX-19, as amended, supercompressiblity calculation. For hand-billed accounts, application of supercompressibility factors will be waived on monthly-billed volumes of 250 dk or less.

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from highest to lowest:
    a. Priority 1 – Firm sales service.
    b. Priority 2 – Small interruptible sales and small interruptible transportation services at the maximum rate on a pro rata basis.
    c. Priority 3 – Large interruptible sales and large interruptible transportation services at the maximum rate on a pro rata basis.
    d. Priority 4 – Small interruptible sales and small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    e. Priority 5 – Large interruptible sales and large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    f. Priority 6 – Gas scheduled to clear imbalances.

    Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

Montana-Dakota reserves the right to provide service to customers with lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

11. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed.

    All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

12. RETURNED CHECK CHARGE – A charge of $20.00 will be collected by the Company for each check charged back to the Company by a bank.

13. TAX CLAUSE – In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any usage fees or any sales, use, franchise or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

    The charges to be added to the customers' service bills under this clause shall be limited to the customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.

14. UTILITY CUSTOMER SERVICES:
    a. The following services will be performed at no charge regardless of the time of performance:

        1. Fire and explosion calls.

2. Investigate hazardous conditions on customer premises, such as gas leaks, odor complaints, combustible fumes.

3. Maintenance or repair of Company-owned facilities on the customer's premises.

b. The following service calls will be performed at no charge during the Company's normal business hours:

1. Cut-ins and cut-outs.

2. Lighting pilots, inspecting, and adjusting gas equipment in connection with establishing service when working cut-in orders.

3. Investigating high bills or inadequate service complaints.

4. Location of underground Company facilities and customer-owned gas service lines for contractors, builders, plumbers, etc.

15. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours, a charge will be made for labor at standard overtime service rates and materials at retail prices. Customers requesting service after the Company's normal business hours will be informed of the after hour service rate and encouraged to have the service performed during normal business hours.

16. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service discontinued shall notify the Company during regular business hours, one business day before service is to be discontinued. Such notice shall be by letter, personal visit or telephone call to the Company's local business office, in communities in which an office is maintained. In other communities such notice shall be given to the Company's representative who services the community or to the nearest business office. Saturdays, Sundays and legal holidays are not considered business days.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

17. INSTALLING TEMPORARY METERING FACILITIES OR SERVICE – A customer requesting a temporary meter installation and service will be charged on the basis of direct costs incurred by the Company.

18. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS – A customer who requests reconnection of service, during normal business hours at a location where same customer discontinued the same service during the preceding 12-month period will be charged the Basic Service Charge applicable during the period service was not being used or a minimum of $30.00. The minimum will be based on standard overtime rates for reconnecting service after normal business hours.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge of $160.00 whenever reinstallation of the remote data acquisition equipment is necessary.

19. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for services are due when rendered and will be considered delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee of $25.00 before restoring gas service which has been disconnected for nonpayment of service bills during normal business hours. Standard overtime rates will apply for services performed after normal business hours.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

GENERAL PROVISIONS Rate 100

20. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS – The Company reserves the right to discontinue service for any of the following reasons:

    a. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

    b. In the event of tampering with the equipment furnished and owned by the Company.

    c. For violation of, or noncompliance with, the Company's rules on file with the Commission.

    d. For failure of the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

    e. For refusal of reasonable access to property to the agent or employee of the Company for the purpose of inspecting the facilities or for testing, reading, maintaining or removing meters.

    The right to discontinue service for any of the above reasons may be exercised whenever and as often as such reasons may occur, and any delay on the part of the Company in exercising such rights, or omission of any action permissible hereunder, shall not be deemed a waiver of its rights to exercise same.

    Nothing in these regulations shall be construed to prevent discontinuing service without advance notice for reasons of safety, health, cooperation with civil authorities, or fraudulent use, tampering with or destroying the Company's facilities.

    The Company may collect a reconnect fee of $30.00 before restoring gas service which has been disconnected for the above causes.

21. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as tampering with the Company's meter, pressure regulator, registration, connections, equipment, seals, valve, procedures or records resulting in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service that has been terminated, without the Company's consent.

    a. Examples of unauthorized use of service includes, but is not limited to, tampering or unauthorized reconnection by the following methods:

        1. Bypass piping around meter.
        2. Bypass piping installed in place of meter.
        3. Meter reversed.
        4. Meter index disengaged or removed.
        5. Service or equipment tampered with or piping connected ahead of meter.
        6. Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
        7. Gas being used after service has been discontinued by the Company.
        8. Gas being used after service has been discontinued by the Company as a result of a new customer turning gas on without the proper connect request.

    b. Any charges for damage to Company property will be billed to the customer. The customer may also be charged for:

        1. Time, material and transportation costs used in investigation or surveillance.
        2. Estimated charge for non-metered gas.
        3. On-premise time to correct situation.
        4. A minimum fee of $30.00 will apply.

        All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company.

c. Reconnection of Service:
Gas service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service, and paid any service charges which are due, including:

1. All delinquent bills, if any.
2. The amount of any Company revenue loss attributable to said tampering.
3. Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in paragraph 20.b.above;
4. Reconnection fee applicable.
5. A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with §V, paragraph 6 CONSUMER DEPOSITS.

22. GAS METER TEST BY CUSTOMER REQUEST - Any customer may request the Company to test its gas meter. The Company shall make the test as soon as possible after receipt of the request. If a request is made within one year after a previous request, the Company may require a deposit as follows:

Meter Rating	Deposit Amount
Residential	
All	$10.00
Non-Residential	
425 CFH* or less	$40.00
426 CFH to 1000 CFH	$40.00
Over 1000 CFH	$70.00

* Cubic feet per hour

The deposit shall be refunded only if the meter is found to have an un-acceptable error, as defined in the Commission's regulations. In the case where a meter is replaced due to malfunction, a customer will be allowed one additional free meter test within 12 months, if requested by the customer.

23. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
    - Rate 102 - Residential Rate for Regular Employees
    - Rate 119 - Interruptible Gas Service Extension Policy
    - Rate 120 - Firm Gas Service Extension Policy
    - Rate 124 - New Installation, Replacement, Relocation and Repair of Gas Service Lines
    - Rate 134 - Rules and Policies for Implementing Master Metering Restrictions

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule

Section No. 5
1st Revised Sheet No. 24
Canceling Original Sheet No. 24

NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

1. The Company will install, at its expense, a service line extending from the main to the connection at the premise regulator and/or meter for all customers. The service line installed by the Company will remain the Company's property.

2. A non-refundable contribution may be required for that portion of the service line cost not supported by the expected or actual connected load. The contribution requirement will be determined based on minimum footage allowances determined annually taking into account the maximum allowable investment defined in Rate 120 and the statewide average installed per foot cost. The Company reserves the right to charge customer the total cost of the installed service line if service is not initiated within 12 months of such installation.

3. The portion of the service line not cost justified shall be charged to the customer on the basis of direct costs to the Company. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply.

4. Where service line location changes are required due to building encroachments (a building is being constructed or is already located over a service line, etc.) or due to a customer request to move a service line, the customer shall be charged on the basis of direct costs incurred by the Company.

5. Whenever a service line is damaged by the customer or someone under the employ of the customer necessitating the service line to be either repaired or replaced in whole or in substantial part, such work shall be charged for on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

6. Service line changes necessary to increase the size and capacity of an existing service line because of increased demand shall be treated in accordance with paragraph 2 above.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 5
Canceling Original Sheet No. 5

DISCONNECT NOTICE

MONTANA-DAKOTA UTILITIES CO

OM

Account Number: _____

DISCONNECT NOTICE

WE WANT TO CONTINUE OUR DEPENDABLE SERVICE TO YOU,
OUR VALUED CUSTOMER, BUT YOU MUST TAKE ACTION NOW.

Date:

Service Address:

_____

Payment of your service account is now past due. Your service will be disconnected on _____ unless your past due amount is paid in full or satisfactory arrangements are made before this date. If service is disconnected, payment in full and a reconnect fee of _____ plus applicable taxes to restore service during normal working hours, plus a deposit or additional deposit of _____ will be required before service is restored.

PLEASE CONTACT US NOW TO AVOID ANY INCONVENIENCE
THANK YOU.

	PAST DUE	CURRENT	ACCT BALANCE
UTILITY:			
DEPOSIT:	$0.00	$0.00	$0.00

DIRECT INQUIRIES TO:
MONTANA-DAKOTA UTILITIES CO
PO BOX 1060
RAPID CITY SD 57709
1 605 342 0187

DIRECT PAYMENTS TO:
MONTANA-DAKOTA UTILITIES CO
PO BOX 5600
BISMARCK ND 58506-5600

DIRECT UNRESOLVED COMPLAINTS TO:
SD PUBLIC UTILITIES COMMISSION
500 E CAPITOL
PIERRE SD 57501
1 800 332 1782

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 8
Canceling Original Sheet No. 8

DISCONTINUANCE NOTICE FOR UNAUTHORIZED USE OF SERVICE

MONTANA-DAKOTA UTILITIES CO.
DISCONTINUANCE NOTICE

NOTICE TO CUSTOMER:
Today we inspected your gas/electric service installation. This inspection has revealed that you are obtaining unauthorized gas/electric service at the address shown below. Under rules and regulations filed with, and approved by, the Public Utility Commission of _____, service can be terminated because of this irregularity. To avoid discontinuance of service bring this card to our office, no later than _____, at the address shown below, and we will discuss the conditions under which your gas/electric service will not be interrupted.

MONTANA-DAKOTA UTILITIES CO.
Address: _____
_____
Telephone No.: _____

Date: _____
Customer: _____
Address: _____
_____
Meter No.: _____
Employee: _____

Date Filed:	June 7, 2004	**Effective Date:**	Service Rendered on and after December 1, 2004
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		
Docket No.:	NG04-004		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS

MONTANA-DAKOTA UTILITIES CO.
DISCONTINUANCE NOTICE

NOTICE TO CUSTOMER:
Today we inspected your gas/electric service installation and under rules and regulations filed with, and approved by, the Public Utility Commission of _____, we are legally authorized to discontinue service due to an irregularity. In order to have your service restored, bring this card to our office, at the address shown below, and we will discuss the conditions under which gas/electric service may be restored.

MONTANA-DAKOTA UTILITIES CO.
Address: _____
_____
Telephone No.: _____

Date: _____
Customer: _____
Address: _____
_____
Meter No.: _____
Employee: _____

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 13
Canceling Original Sheet No. 13

GUARANTEE OF PAYMENT FOR NATURAL GAS AND/OR ELECTRIC SERVICE BY A SECOND PARTY IN LIEU OF A DEPOSIT

GUARANTEE OF PAYMENT FOR NATURAL GAS AND/OR
ELECTRIC SERVICE BY A SECOND PARTY IN LIEU OF A DEPOSIT

MONTANA-DAKOTA UTILITIES CO.
GUARANTEE OF PAYMENT FOR
NATURAL GAS AND/OR ELECTRIC SERVICE

(Date)

To: Montana-Dakota Utilities Co.

(Address)

(City, State, Zip Code)

For value received, I, _____ (Name of Guarantor), do hereby absolutely guarantee to pay to Montana-Dakota Utilities Co. (Montana-Dakota), upon its request and at the location listed above, the outstanding balance accrued by _____ (Name of Customer) in the event that Customer's bill for natural gas and/or electricity provided by Montana-Dakota at _____ (Customer's Service Address) is not paid when due; however, liability under this Guarantee, other than the collection costs noted below, shall not exceed the sum of $ _____. As Guarantor, I request copies of all disconnect notices sent to the Customer.

Liability under this Guarantee shall begin on _____, 19 ____, and shall continue until Customer has paid for natural gas and/or electric service when due in a prompt and satisfactory manner for twelve consecutive months in accordance with Public Service Commission or Public Utilities Commission rules. I expressly waive receipt of notice of Montana-Dakota's acceptance of my guarantee.

I also agree to pay any and all costs that Montana-Dakota may incur in the collection of this guarantee. In the event legal action is required or becomes necessary to collect the outstanding balance accrued by the Customer from me under this guarantee, I agree to pay all legal fees, including attorneys' fees, in the amount the court determines is reasonable.

I ACKNOWLEDGE THAT I HAVE CAREFULLY READ THE ABOVE GUARANTEE AGREEMENT AND THAT I HAVE RECEIVED A COPY OF IT.

GUARANTOR:

_____ (Signature of Witness)

_____ (Signature of Guarantor)

_____ (Guarantor's Mailing Address)

_____ (Guarantor's Street Address—If Different than Mailing Address)

_____ (City, State, Zip Code)

_____ (Guarantor's Telephone Number)

DIVISION OFFICE – White Copy CUSTOMER COPY – Yellow Copy GUARANTOR COPY – Pink Copy

Date Filed:	June 7, 2004	**Effective Date:**	Service Rendered on and after December 1, 2004
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		
Docket No.:	NG04-004		

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 16
Canceling Original Sheet No. 16

FINAL NOTICE PRIOR TO DISCONNECT

MONTANA-DAKOTA UTILITIES CO

Account Number: _____

FINAL NOTICE

WE WANT TO CONTINUE OUR DEPENDABLE SERVICE TO YOU,
OUR VALUED CUSTOMER, BUT YOU MUST TAKE ACTION NOW.

Date:

Service Address:

YOUR SERVICE ACCOUNT IS SERIOUSLY PAST DUE.

THIS IS YOUR FINAL NOTIFICATION THAT YOUR GAS AND/OR ELECTRIC SERVICE WILL BE DISCONTINUED IMMEDIATELY -

Unless your past due amount is paid in full or satisfactory arrangements are made in person to the CREDIT DEPARTMENT of MONTANA-DAKOTA UTILITIES CO. by 5:00 p.m. on _____.

If service is disconnected, payment in full and a reconnect fee of _____ to restore service during normal working hours plus a deposit or additional deposit of will be required before service is restored.

PLEASE CONTACT US NOW TO AVOID ANY INCONVENIENCE
THANK YOU.

	PAST DUE	CURRENT	ACCT BALANCE
UTILITY:			
DEPOSIT:	$0.00	$0.00	$0.00

DIRECT INQUIRIES TO:
MONTANA-DAKOTA UTILITIES CO
PO BOX 1060
RAPID CITY SD 57709
1 605 342 0187

DIRECT UNRESOLVED COMPLAINTS TO:
SD PUBLIC UTILITIES COMMISSION
500 E CAPITOL
PIERRE SD 57501
1 800 332 1782

NB04-004

RECEIVED
NOV 17 2004
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

Jacobson, David

From: Collins, Karen [Karen.Collins@mdu.com]
Sent: Wednesday, November 17, 2004 9:10 AM
To: 'david.jacobson@state.sd.us'; Brett Koenecke (koenecke@magt.com)
Cc: Bosch, Stephanie; Aberle, Tamie; Ball, Don; Mulkern, Rita
Subject: Revised SD tariff pages and Notice to customers

Attached is a PDF file with changes to the following tariff sheets:

Section No. 3-2nd Revised Sheet No. 13, Canceling 1st Revised Sheet No. 13

Section No. 6-1st Revised Sheet No. 12, Canceling Original Sheet No. 12

Also included in the PDF file per request by Dave is a Notice to Customers (bill insert information).

If you have any questions, please contact either myself at 800-431-5733 or Stephanie Bosch at 701-222-7983. Thanks.

Karen M. Collins
Regulatory Analyst
Montana-Dakota Utilities Co.
400 North 4th Street
Bismarck, ND

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 3
2nd Revised Sheet No. 13
Canceling 1st Revised Sheet No. 13

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served, except for those communities set forth on Rate 66, for customers otherwise qualifying for service under Firm General Gas Service Rate 70. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.35 per day
For customers with meters rated over 500 cubic feet per hour	$0.70 per day
Distribution Delivery Charge:	$1.175 per dk
Cost of Gas:	
Winter – Bills rendered October 1 through May 31	Determined Monthly – See Rate Summary Sheet for Current Rate
Summer – Bills rendered June 1 through September 30	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.11, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 2

Section No. 6
1st Revised Sheet No. 12
Canceling Original Sheet No. 12

Reserved for Future Use

Date Filed:	June 7, 2004	**Effective Date:**	Service Rendered on and after December 1, 2004
Issued By:	Donald R. Ball Asst. Vice President-Regulatory Affairs		
Docket No.:	NG04-004		

IN THE MATTER OF THE APPLICATION OF
MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY
TO INCREASE RATES FOR NATURAL GAS SERVICE

RECEIVED
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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

STAFF MEMORANDUM SUPPORTING
SETTLEMENT STIPULATION

DOCKET NG04-004

Staff submits this memorandum in support of the settlement Stipulation filed November 15, 2004, by Staff and Montana-Dakota Utilities Co. (collectively, "the parties") in the above captioned matter.

BACKGROUND

On June 7, 2004, Montana-Dakota Utilities Co. (MDU) filed for approval to increase rates for natural gas service in its Black Hills service territory by $1,281,417. MDU's proposed increase was based on a historic test year ended December 31, 2003, adjusted for projected changes and a return on common equity of 11%. MDU witnesses submitted testimony stating that the increase was necessary because of increased operating expenses driven largely by increases in labor, benefit costs and depreciation expense.

On June 10, 2004, the Commission gave notice of the application and the intervention deadline of July 9, 2004. By Orders dated June 30th, 2004, and July 27, 2004, the Commission suspended the proposed rates in this matter. By Order dated August 26, 2004, the Commission set a procedural schedule for this application which was amended by a Commission Order dated October 4, 2004. Commission Staff filed its direct testimony on October 19, 2004. On October 22, 2004, the parties met to discuss possible settlement of the rate increase request and discussions have continued to where MDU and Commission Staff have now reached a settlement of all of their outstanding differences.

On November 15, 2004, the Parties filed a Joint Motion with the Commission requesting approval of the Settlement Stipulation.

Overview of the Settlement

MDU's filing was based on a historic test year ending December 31, 2003, adjusted for 2004 projected changes and a claimed 9.613% overall rate of return reflecting a 11% return on common equity capital. MDU's distribution of the rate increase was guided by a class cost of service study. MDU's proposed increase of $1,281,417 was approximately 2.2% of MDU's test year revenue of approximately $58.3 million which included adjustments by MDU for normal weather, an annualization of increased rates

from Docket NG02-011, projected increased gas costs, and projected increased customer numbers. Staff's testimony, submitted after comprehensive analysis of the filing and substantial discovery, was based on the historical test year ended December 31, 2003, updated for known and measurable changes, a 8.734% rate of return based on a return on common equity of 9.25%, and a distribution of the rate increase based on an independent class cost of service study. Staff's testimony, based on the evidence gathered and information supplied by MDU up to the point of filing, indicated that an increase of $210,448 or .46% was warranted based on Staff adjusted test year revenues of approximately $45.8 million. Staff adjustments to test year revenues included normal weather and annualized rates from Docket NG02-011. The difference between Staff and MDU revenues resulted primarily from MDU applying projected gas costs and Staff using actual test year gas costs.

During the time elapsed since Staff's testimony was filed, MDU provided additional information demonstrating and substantiating additional adjustments to reflect changes in MDU's costs that are now known and measurable. Staff has carefully reviewed this updated information and revised certain expense, plant, and other of MDU's claimed costs of service. MDU has also modified certain positions it established in its prefiled testimony for settlement purposes. Reflecting the substantial additional information obtained since the filing of Staff's testimony, the settlement would allow for an increase in rates of $669,549 or approximately 1.5% of Staff adjusted test year revenues which is approximately 52% of MDU's initial request. Settlement was pursued by Staff with the objective of obtaining a comprehensive resolution of all issues in the filing, based on sound regulatory principles. Staff believes this settlement achieves that purpose and avoids unnecessary litigation.

Following are the issues on which the Settlement differs from the analysis reflected in Staff's prefiled testimony:

Operating Revenue and Expense

Labor - To analyze MDU's labor expense it is necessary to separately consider union and non-union labor as each group receives changes to compensation levels in different amounts at different times. Regarding non-union labor, Staff's prefiled testimony reflected only test year actual expenses as MDU's initial filing and subsequent data responses provided only budgeted projections of post test year increases. During settlement discussions, MDU provided evidence that showed an increase to non-union compensation of 4.65% occurred on January 1, 2004. Staff's settlement allowance reflects the updated non-union labor increase, as it has taken effect and is known and measurable.

MDU, during settlement, also took issue with the method Staff used to compute the percentage increase in wages for union employees. Staff derived a percentage increase by averaging the increases granted to each job position and giving each job position equal weight as this was the best information available at that time. During

settlement discussions, MDU provided information allowing each job position to be weighted by number of employees. The result of the revised calculation changed the 2003 union increase from 6.72% to 7.3% and the 2004 union increase from 6.31% to 6.41%. Staff accepted this revised average increase calculation as it results in a more accurate determination of actual increases granted. The above adjustments resulted in an increase to Staff's labor adjustment of approximately $104,000 including associated labor taxes.

Benefits, Pension and Post Retirement Expense - Staff's prefiled testimony updated MDU's test year pension and post retirement expense to the twelve month period ending 07/31/04. Each year, Towers Perrin performs an actuarial study for MDU which contains a current year analysis and a five year forecast of these expense categories. During settlement discussions MDU provided an updated adjustment utilizing the current actuarial study which Staff believes is consistent with the Commission's decision in NG94-012, a prior rate case where the Commission accepted FAS 106 accounting treatment. Also, subsequent to Staff filing direct testimony, MDU provided updated actual medical/dental, 401k and workers compensation benefits expense as of 9/31/04. In summary, the updates increased medical/dental and pension expense and decreased post retirement, 401-K and Workers Compensation expenses from the levels utilized in Staff's prefiled testimony. Together, these updates increased the revenue requirement of MDU by approximately $154,000.

Rate Case Expense - Staff's proposed five year amortization was adopted and the amount spent on this case by the parties was updated at the time of settlement, adding $1,000 to the revenue requirement.

Inflation Adjustment - During settlement negotiations MDU proposed an inflation adjustment which annualized operation and maintenance (O&M) expenses not otherwise adjusted by applying one-half of the actual inflation rate experienced during the historic test year to the 12/31/03 Other O&M expenses not otherwise adjusted. MDU's adjustment further applied the most recent available post test year inflation rate to this annualized amount bringing test year expense to current inflation adjusted levels. After review and refinement, Staff accepted this adjustment resulting in an increase in MDU's revenue deficiency of approximately $38,000.

Interest on Customer Deposits - Staff's filed case included MDU held customer deposits as a deduction from rate base. MDU expressed its concern regarding Staff's position in that it did not recognize the interest that MDU pays on such deposits. After discussion, Staff amended its position to include the interest expense that MDU pays on customer deposits in its cost of service calculation. This adjustment resulted in an increase of approximately $11,000 to MDU's revenue deficiency.

Cost of Gas - Staff's case relied on test year gas commodity costs for cost of service calculations. During settlement, MDU argued that their 2004 estimated cost of gas better represented current conditions than the historic test year costs. Staff contended

that MDU's estimated 2004 cost of gas is not known and violates accounting matching principles. Both sides agreed that the cost of gas is a direct flow through in the PGA and does not affect the cost of service except for issues indirectly relating to commodity costs such as gross receipts tax, uncollectible accounts and company consumption. MDU provided information to Staff showing that the most recent 12 month gas costs ending September 2004 were $3,557,204 higher than test year commodity costs. Staff objects to using forecasted gas costs, but the updated gas costs are actual costs that have occurred since the end of the test year. While there may be some unresolved related matching issues, Staff does not believe any such issues override the unprecedented change in natural gas costs of the past several months, costs which are not expected to reverse in the near future.

As a result, Staff and MDU agree to use the most current available twelve month gas costs for adjustments relating only to gross receipts tax, uncollectible accounts and company consumption. These adjustments resulted in a $20,000 increase in the cost of service.

Discounted Rate Adjustment - Staff's prefiled case reflected the application of maximum rates for those rates capable of being flexed in order to retain customers or meet competitive forces. During settlement discussions, MDU provided additional evidence that the rate 71 and 81 customers that had been given discounts pursuant to currently tariffed flex rates had provided adequate margins to help recover the fixed costs of the other customers. Given this contribution of fixed cost recovery and MDU's assurances that these rates were necessary to retain these customers, Staff has agreed to allow for the recovery of these discounts from the other customers. The effect of this adjustment increased MDU's revenue requirement by approximately $5,000.

Rate Base Items

Plant Additions - Staff's case as filed included non-revenue producing post test year plant additions through July 31, 2004. During settlement, MDU provided updated information including actual plant additions completed through September 30, 2004. The net affect of adding these plant additions to Staff's case and the related adjustments to accumulated depreciation, depreciation expense, deferred taxes, accumulated deferred income taxes, ad valorem taxes and a small error correction resulted in a $53,000 increase in MDU's revenue deficiency.

Cost of Capital Issues

Return on Common Equity - Staff's prefiled revenue requirement determination reflected a 9.25% return on equity capital (ROE). Staff's cost of capital evidence supported an ROE in the range of 8.5% to 9.5% while MDU's filed case claimed a return on equity of 11%. Settlement discussions did not result in a mutually agreed upon ROE. Staff arrived at an acceptable settlement rate increase based on positions taken regarding all issues involved in the case, including an ROE of 9.5%. MDU has agreed to the resulting dollar amount of the rate increase but has valued certain issues differently than Staff, concluding that the settlement results in an ROE higher than that reflected in this memo and the accompanying attachments. Staff's determination of an acceptable settlement rate increase based on an ROE at a level higher than that reflected in its filed case is justified because this rate of return remains within its recommended range of reasonable returns and further, because it allowed the parties to achieve an overall settlement thereby avoiding the time and cost of full evidentiary Commission hearings. Increasing the 9.25% ROE reflected in its filed testimony by 0.25% added approximately $35,000 to the revenue requirement justified by Staff.

Capital Structure - As indicated above, Staff believes that the overall settlement will result in a return on common equity capital that is within the range recommended by its witness. The overall rate of return on rate base also reflects the Staff witness' proposed June 30, 2004 capital structure and debt costs, updated to reflect changes that have occurred since that date. Specifically, the updates include the retirement of a $15 million debt issue on October 1, 2004, and recognition of actual changes in common equity capitalization that occurred through September 30, 2004. The combined effect of these changes increased Staff's revenue requirement by approximately $38,000.

Rate Design Issues

Distribution of Settlement Increase - In its rate filing, MDU proposed that approximately 70% of its proposed $1.3 million rate increase be allocated to Residential customers with the remainder allocated to the Firm General Service (29.5%) and Large Interruptible (0.5%) groups. Staff challenged the class cost of service study on which the Company's distribution of the proposed increase was based and presented an alternative cost study supporting a rate design that would have placed approximately 42% of the increase on Residential customers, 55% on Firm General Service customers and 3% on Small and Large Interruptible users. The fundamental difference between the parties' cost studies lies in MDU's allocation of 36% of the cost of distribution mains on the basis of the number of customers in each class with the remainder allocated on the basis of each class' requirements for pipeline capacity. Staff allocated 100% of these costs on the basis of pipeline capacity requirements. Based on the settlement rate increase of $669,549, the Company and Staff distributions would have resulted in the following increases in customer billings (i.e. including the PGA cost of purchased gas component):

Rate Increase Based on:

	MDU Distribution	Staff Distribution
Residential	1.78%	1.05%
Firm General Service	1.26%	2.36%
Small Interruptible	0.00%	0.83%
Large Interruptible	0.59%	3.26%

Recognizing that these differences arise out of competing theories of cost allocation, as opposed to definitive and undisputable assignments of costs to each class, Staff agreed in settlement of the issue to a uniform, across-the-board increase of 1.572% to all classes for which the Company had proposed a rate increase.

As indicated above, this uniform increase is the increase in the total billings to customers, including PGA charges. Removing PGA charges from the equation indicates that the settlement increase in base rates, which overall is 5.94%, is 5.38% for Residential customers, 8.28% for Firm General Service customers and 6.82% for Large Interruptible users.

Customer Service Charges - Based on its analysis of its "customer costs", MDU proposed increases in all customer service charges. Staff disputed the Company's cost analysis and presented its own analysis of costs directly associated with customer service. As illustrated in Exhibit___(RGT-3), this analysis supported the Company's proposed service charges for Firm General Service and Large Interruptible customers but indicated that the increase proposed for the Residential class was not justified. The settlement reflects Staff's position.

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Revenue Requirement
Adjusted Test Year Ended December 31, 2003

Line	Description		Staff South Dakota - Gas Adjusted 2003 Test Year
	(a)		(b)
1	Average Rate Base	$	17,392,395
2	Adjusted Test Year Operating Income		1,117,905
3	Earned Rate of Return		6.428%
4	Proposed Rate of Return		8.917%
5	Required Operating Income		1,550,904
6	Income Deficiency (Excess)		432,999
7	Gross Revenue Conversion Factor		1.53846
8	Revenue Deficiency (Excess)		666,152
9	Bad Debts on Revenue Deficiency (0.36%)		2,398
10	Gross Receipts Tax (at 0.0015)		999
11	**Total Revenue Deficiency (Excess)**		**669,549**
12	Adjusted Test Year Revenue		45,827,939
13	**Revenue Requirement**	**$**	**46,497,488**

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Operating Income Statement With Known and Measurable Adjustments and Revenue Adjustment
Adjusted Test Year Ended December 31, 2003

Line No.	Description	South Dakota Per Books	Total Staff Adjustments	Adjusted Test Year	Revenue Adjustment	Adjusted Test Year with Revenue Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)
1	OPERATING REVENUES:					
2	Sales (480-485) (including unbilled)	$ 44,201,634	$ 1,094,274	$ 45,295,908	$ 669,549	$ 45,965,457
3	Transpiration (489) (including unbilled)	363,186	(47,776)	315,410		315,410
4	Other Revenues (488, 493, 495)	216,621	-	216,621		216,621
5	**TOTAL OPERATING REVENUES**	**44,781,441**	**1,046,498**	**45,827,939**	**669,549**	**46,497,488**
6	OPERATING EXPENSES:					
7	Operation and Maintenance:					
8	Natural Gas (accts 728, 804, 805, 808)	34,335,947	-	34,335,947		34,335,947
9	Labor	4,033,579	262,292	4,295,871		4,295,871
10	Benefits Expense	690,769	240,135	930,904		930,904
11	Insurance Expense	255,242	(3,643)	251,599		251,599
12	Uncollectible Account Expense	139,674	-	139,674		139,674
13	Regulatory Commission Expense	1,869	-	1,869		1,869
14	Other Operation and Maintenance	2,143,676	272,700	2,416,376		2,416,376
15	Total Operation and Maintenance	41,600,756	771,484	42,372,240	-	42,372,240
16	Depreciation and Amortization	1,815,584	(360,240)	1,455,344		1,455,344
17	Gain on Sale	-	(82,100)	(82,100)		(82,100)
18	Taxes:					
19	Property Taxes	388,906	6,993	395,899		395,899
20	Payroll Taxes					
21	FICA	272,985	23,659	296,644		296,644
22	Federal Unemployment	3,880	341	4,221		4,221
23	State Unemployment	10,598	420	11,018		11,018
24	Gross Receipts Tax	46,953	27,125	74,078	999	75,077
25	Federal Income Taxes	(1,118,415)	305,941	(812,474)	233,153	(579,321)
26	Deferred Income Taxes	997,246	(15,015)	982,231		982,231
27	Investment Tax Credit	-	-	-		-
28	Other Taxes	12,933	-	12,933		12,933
29	Total Taxes	615,086	349,464	964,550	234,152	1,198,702
30	**TOTAL OPERATING EXPENSES**	**44,031,426**	**678,608**	**44,710,034**	**234,152**	**44,944,186**
31	**OPERATING INCOME**	**$ 750,015**	**$ 367,890**	**$ 1,117,905**	**$ 435,397**	**$ 1,553,302**
32	Rate Base	17,836,071		$ 17,392,395		$ 17,392,395
33	Rate of Return	4.205%		6.428%		8.931%
34	Staff Proposed Rate of Return			8.917%		8.917%

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2003

Line No.	Description	South Dakota Per Books	Interest Sync	Postage Expense	Depreciation Study Expense	Office Suplies	Uncollectible Accounts	Company Consumption	Sale of Plant Assets (NG02-011)	Depr. Rate Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	OPERATING REVENUES:									
2	Sales (480-485) (including unbilled)	$ 44,201,634								
3	Transportation (489) (including unbilled)	363,186								
4	Other Revenues (488, 493, 495)	216,621								
5	TOTAL OPERATING REVENUES	44,781,441	-	-	-		-	-	-	-
6	OPERATING EXPENSES:									
7	Operation and Maintenance:									
8	Natural Gas (accts 804, 805, 808)	34,335,947								
9	Labor	4,033,579								
10	Benefits Expense	690,769								
11	Insurance Expense	255,242								
12	Uncollectible Account Expense	139,674								
13	Regulatory Commission Expense	1,869								
14	Other Operation and Maintenance	2,143,676		(4,692)	3,050	(15,167)	16,573	2,761		218,282
15	Total Operation and Maintenance	41,600,756	-	(4,692)	3,050	(15,167)	16,573	2,761	-	218,282
16	Depreciation and Amortization	1,815,584								(407,367)
17	Gain on Sale	-							(82,100)	
18	Taxes:									
19	Property Taxes	388,906								
20	Payroll Taxes									
21	FICA	272,985		-	-	-	-	-	-	-
22	Federal Unemployment	3,880		-	-	-	-	-	-	-
23	State Unemployment	10,598		-	-	-	-	-	-	-
24	Gross Receipts Tax	46,953		-	-	-	-	-	-	-
25	Federal Income Taxes (35%)	(1,118,415)	58,665	1,642	(1,068)	5,308	(5,801)	(966)	28,735	66,180
26	Deferred Income Taxes	997,246								
27	Investment Tax Credit	-								
28	Other Taxes	12,933								
29	Total Taxes	615,086	58,665	1,642	(1,068)	5,308	(5,801)	(966)	28,735	66,180
30	TOTAL OPERATING EXPENSES	44,031,426	58,665	(3,050)	1,982	(9,859)	10,772	1,795	(53,365)	(122,905)
31	OPERATING INCOME	$ 750,015	$ (58,665)	$ 3,050	$ (1,982)	$ 9,859	$ (10,772)	$ (1,795)	$ 53,365	$ 122,905

Highlighted cells reflect direct changes from staff's filed case

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2003

Line No.	Description	Plant Additions	Advolem Tax Adjustment on Plant Additions	Distribution Rates and Weather Normalized	Industry Dues	Advertising	Economic Develoment	Rate Case Expense	Closing/Filing and Proir Period Adjustments	GRT on Test Year Revenues
	(a)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
1	OPERATING REVENUES:									
2	Sales (480-485) (including unbilled)			$ 1,094,274						
3	Transportation (489) (including unbilled)			(47,776)						
4	Other Revenues (488, 493, 495)									
5	**TOTAL OPERATING REVENUES**	-	-	1,046,498	-	-	-	-	-	-
6	OPERATING EXPENSES:									
7	Operation and Maintenance:									
8	Natural Gas (accts 804, 805, 808)									
9	Labor									
10	Benefits Expense									
11	Insurance Expense									
12	Uncollectible Account Expense									
13	Regulatory Commission Expense									
14	Other Operation and Maintenance	28,871			(31,301)	(32,142)	(776)	38,688		
15	Total Operation and Maintenance	28,871	-	-	(31,301)	(32,142)	(776)	38,688	-	-
16	*Depreciation and Amortization*	47,127								
17	Gain on Sale									
18	Taxes:									
19	Property Taxes		6,993							
20	Payroll Taxes									
21	FICA	-	-	-	-	-	-	-	-	-
22	Federal Unemployment	-	-	-	-	-	-	-	-	-
23	State Unemployment	-	-	-	-	-	-	-	-	-
24	Gross Receipts Tax	-	-	1,570	-	-	-	-	-	25,555
25	Federal Income Taxes (35%)	(56,047)	(2,448)	365,725	10,955	11,250	272	(13,541)	46,139	(8,944)
26	Deferred Income Taxes	29,448							(44,463)	
27	Investment Tax Credit									
28	Other Taxes									
29	Total Taxes	(26,599)	4,545	367,295	10,955	11,250	272	(13,541)	1,676	16,611
30	**TOTAL OPERATING EXPENSES**	49,399	4,545	367,295	(20,346)	(20,892)	(504)	25,147	1,676	16,611
31	**OPERATING INCOME**	$ (49,399)	$ (4,545)	$ 679,203	$ 20,346	$ 20,892	$ 504	$ (25,147)	$ (1,676)	$ (16,611)

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Gas Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2003

Line No.	Description	Labor	Benefits	Insurance Expense	Interest on Customer Deposits	Inflation Adjustment	Total Staff Adjustments	Adjusted Test Year
	(a)	(t)	(u)	(v)	(w)		(x)	(y)
1	OPERATING REVENUES:							
2	Sales (480-485) (including unbilled)						$ 1,094,274	$ 45,295,908
3	Transportation (489) (including unbilled)						(47,776)	315,410
4	Other Revenues (488, 493, 495)						-	216,621
5	**TOTAL OPERATING REVENUES**	-	-	-	-	-	1,046,498	45,827,939
6	OPERATING EXPENSES:							
7	Operation and Maintenance:							
8	Natural Gas (accts 804, 805, 808)						-	34,335,947
9	Labor	262,292					262,292	4,295,871
10	Benefits Expense		240,135				240,135	930,904
11	Insurance Expense			(3,643)			(3,643)	251,599
12	Uncollectible Account Expense						-	139,674
13	Regulatory Commission Expense						-	1,869
14	Other Operation and Maintenance				11,134	37,419	272,700	2,416,376
15	Total Operation and Maintenance	262,292	240,135	(3,643)	11,134	37,419	771,484	42,372,240
16	Depreciation and Amortization						(360,240)	1,455,344
17	Gain on Sale						(82,100)	(82,100)
18	Taxes:							
19	Property Taxes						6,993	395,899
20	Payroll Taxes							
21	FICA	23,659	-	-	-	-	23,659	296,644
22	Federal Unemployment	341	-	-	-	-	341	4,221
23	State Unemployment	420	-	-	-	-	420	11,018
24	Gross Receipts Tax	-	-	-	-	-	27,125	74,078
25	Federal Income Taxes (35%)	(100,349)	(84,047)	1,275	(3,897)	(13,097)	305,941	(812,474)
26	Deferred Income Taxes						(15,015)	982,231
27	Investment Tax Credit						-	-
28	Other Taxes						-	12,933
29	Total Taxes	(75,929)	(84,047)	1,275	(3,897)	(13,097)	349,464	964,550
30	**TOTAL OPERATING EXPENSES**	186,363	156,088	(2,368)	7,237	24,322	678,608	44,710,034
31	**OPERATING INCOME**	$ (186,363)	$ (156,088)	$ 2,368	$ (7,237)	$ (24,322)	$ 367,890	$ 1,117,905

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2003

Line No.	Description	South Dakota Test Year Average Per Books	Total Pro Forma Adjustments	South Dakota Pro Forma Rate Base
	(a)	(b)	(c)	(d)
1	Gas Plant in Service (101)			
2	Distribution (including Intangible - 303)	$ 31,872,892	$ 268,144	$ 32,141,036
3	General (including Intangible - 303)	9,390,638	359,951	9,750,589
4	Common (including Intangible 303)	2,731,501	343,512	3,075,013
5	Total Gas Plant in Service (101)	43,995,031	971,607	44,966,638
6	Gas - Completed Construction Not Classified (106)	446,103	-	446,103
7	Total Plant in Service (101 and 106)	44,441,134	971,607	45,412,741
8	Accumulated Depreciation			
9	Distribution (including Intangible)	21,493,907	(183,296)	21,310,611
10	General (including Intangible)	2,130,202	884,156	3,014,358
11	Common (including Intangible)	1,122,147	10,728	1,132,875
12	Total Accumulated Depreciation	24,746,256	711,588	25,457,844
13	TOTAL NET GAS PLANT IN SERVICE	19,694,878	260,019	19,954,897
14	Additions to Rate Base:			
15	Material and Supplies	271,563	(7,075)	264,488
16	Fuel Stocks	-	-	-
17	Prepayments	76,422	25,865	102,287
18	Advanced Tax Collection	-	(96,840)	(96,840)
19	Working Capital	-	(382,215)	(382,215)
20	Other	150,700	90,493	241,193
21	TOTAL ADDITIONS TO RATE BASE	498,685	(369,772)	128,913
22	Deductions to Rate Base:			
23	Accumulated Deferred Income Taxes	1,921,358	29,448	1,950,806
24	Accumulated Investment Tax Credit	21,525	103,290	124,815
25	Customer Advances for Construction	57,168	(4,064)	53,104
26	Customer Deposits	159,060	-	159,060
27	Accumulated Provision for Uncollectibles	42,404	-	42,404
28	Accumulated Provision for Injuries and Damages	155,977	-	155,977
29	Miscellaneous Operating Provisions	-	-	-
30	Other	-	205,249	205,249
31	TOTAL DEDUCTIONS TO RATE BASE	2,357,492	333,923	2,691,415
32	**TOTAL SOUTH DAKOTA RATE BASE**	**$ 17,836,071**	**$ (443,676)**	**$ 17,392,395**

Montana-Dakota Utilities Co.
Docket NG04-004
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2003

Line No.	Description	South Dakota Test Year Average Per Books	Investment Tax Credits	Depreciation Rate Change	Plant Additions	Updates and Working Capital	Average Unamortized Rate Case Expense	Unamortized Balance Gain on Sale (NG02-012)	Total Staff Adjustments	Total Staff South Dakota Rate Base
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Gas Plant in Service (101)									
2	Distribution (including Intangible - 303)	$ 31,872,892			268,144				268,144	$ 32,141,036
3	General (including Intangible - 303)	9,390,638			359,951				359,951	9,750,589
4	Common (including Intangible 303)	2,731,501			343,512				343,512	3,075,013
5	Total Gas Plant in Service (101)	43,995,031	-	-	971,607	-	-	-	971,607	44,966,638
6	Gas - Completed Construction Not Classified (106)	446,103							-	446,103
7	Total Gas Plant in Service (101 and 106)	44,441,134	-	-	971,607	-	-	-	971,607	45,412,741
8	Accumulated Depreciation									
9	Distribution (including Intangible)	21,493,907		(187,514)	4,218				(183,296)	21,310,611
10	General (including Intangible)	2,130,202		866,766	17,390				884,156	3,014,358
11	Common (including Intangible)	1,122,147		(8,718)	19,446				10,728	1,132,875
12	Total Accumulated Depreciation	24,746,256	-	670,534	41,054	-	-	-	711,588	25,457,844
13	TOTAL NET GAS PLANT IN SERVICE	19,694,878	-	(670,534)	930,553	-	-	-	260,019	19,954,897
14	Additions to Rate Base:									
15	Material and Supplies	271,563				(7,075)			(7,075)	264,488
16	Fuel Stocks	-							-	-
17	Prepayments	76,422				25,865			25,865	102,287
18	Advanced Tax Collection	-				(96,840)			(96,840)	(96,840)
19	Working Capital	-				(382,215)			(382,215)	(382,215)
20	Other	150,700				(9,254)	99,747		90,493	241,193
21	TOTAL ADDITIONS TO RATE BASE	498,685	-	-	-	(469,519)	99,747	-	(369,772)	128,913
22	Deductions to Rate Base:									
23	Accumulated Deferred Income Taxes	1,921,358			29,448				29,448	1,950,806
24	Accumulated Investment Tax Credit	21,525	103,290						103,290	124,815
25	Customer Advances for Construction	57,168				(4,064)			(4,064)	53,104
26	Customer Deposits	159,060							-	159,060
27	Accumulated Provision for Uncollectibles	42,404							-	42,404
28	Accumulated Provision for Injuries and Damages	155,977							-	155,977
29	Miscellaneous Operating Provisions	-							-	-
30	Other	-						205,249	205,249	205,249
31	TOTAL DEDUCTIONS TO RATE BASE	2,357,492	103,290	-	29,448	(4,064)	-	205,249	333,923	2,691,415
32	**TOTAL SOUTH DAKOTA RATE BASE**	**$ 17,836,071**	**(103,290)**	**(670,534)**	**901,105**	**(465,455)**	**99,747**	**(205,249)**	**(443,676)**	**$ 17,392,395**

Highlighted cells reflect direct changes from staff's filed case

Montana-Dakota Utilities Co.
South Dakota - Gas
Cash Working Capital
Test Year Ended 12/31/03

Exhibit__(DAJ-1)
Schedule 1
Page 1

Line	Description	South Dakota Per Books	Adjustments	Pro Forma Expense	Expense Per Day	Expense Lead Days	Expense Dollar Days
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Operation & Maintenance						
1	Gas Purchases	$ 34,335,947	$ -	$ 34,335,947	$ 94,071	41.2	$ 3,875,725
2	Labor Expense	4,033,579	262,292	4,295,871	11,770	19	223,630
3	Fringe Benefit	690,769	240,135	930,904	2,550	27.7	70,635
4	Insurance Expense	255,242	(3,643)	251,599	N/A		
5	Uncollectible Accounts Exp.	139,674	-	139,674	383	230.6	88,320
6	Regulatory Commission Exp.	1,869	-	1,869	N/A		
7	Other O & M Expense	2,143,676	272,700	2,416,376	6,620	16.4	108,568
8	Total O & M	41,600,756	771,484	42,372,240	115,394		4,258,310
9	Depreciation & Amortization	1,815,584	(360,240)	1,455,344	3,987	0	-
10	Deferred Income Taxes	997,246	(15,015)	982,231	2,691	0	-
11	Ad Valorem Tax	388,906	6,993	395,899	1,085	395.25	428,846
12	Payroll - FICA	272,985	23,659	296,644	813	19	15,447
13	Payroll - FUTA	3,880	341	4,221	12	47	564
14	Payroll - SUTA	10,598	420	11,018	30	47	1,410
15	S D Gross Receipts Tax	46,953	28,124	75,077	206	379.3	78,136
16	Federal Income Tax	(1,118,415)	539,094	(579,321)	(1,587)	37	(58,719)
17	Interest on Long Term Debt	811,985	(167,613)	644,372	1,765	91.3	161,145
18	Preferred Stock Dividends			38,111	104	45.6	4,742
19	Total	$ 44,830,478	$ 827,247	$ 45,695,836	$ 124,500	39.28	$ 4,889,881.00

20	Revenue Lag Days	36.21
21	Expense Lead Days	39.28
22	Net Days	(3.07)
23	Expense per Day	124,500
24	Cash Working Capital	(382,215)

Montana-Dakota Utilities Co.
South Dakota - Gas
Tax Collections Available
Test Year Ended 12-31-03

Exhibit__(DAJ-1)
Schedule 2
Page 1

Line	Item	South Dakota Per Books	Adjustments	Pro Forma Collections	Collections Per Day	Collection Lead Days	Available
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Employee FICA	$ 272,985	$ 23,659	$ 296,644.00	$ 812.72	19	$ 15,441.74
2	Federal Witholding	457,333	29,739	487,072.00	$ 1,334.44	19	$ 25,354.43
3	South Dakota Sales Tax	2,107,513	68,641.88	2,176,154.88	$ 5,962.07	9.4	$ 56,043.44
4	Total						$ 96,839.62

Exhibit___(BLC-1)
Schedule 1
Docket No. NG04-004

Montana-Dakota Utilities Co.
Cost of Capital at September 30, 2004

Line No.	Component	Balance as of June 30, 2004	% of Total	Cost	Weighted Cost
	(a)	(b)	(c)	(d)	(e)
1	Long Term Debt	$145,850,000	42.698%	8.677%	3.705%
2	Preferred Stock	$16,200,000	4.743%	4.620%	0.219%
3	Common Equity	$179,535,470	52.559%	9.500%	4.993%
4	Total	$341,585,470	100.000%		8.917%

MONTANA-DAKOTA UTILITIES
REVENUE INCREASE
COMPARISON

LINE NO.	BASE RATE REVENUE INCREASE by CUSTOMER CLASS	Dekatherms	Dekatherms	Test Year Revenue (Current Rates)	Proposed Revenue	Revenue (Inc./Dec.)	Percent (Inc./Dec.)
1	RESIDENTIAL	3,035,759	3,035,759	$7,683,206	$8,096,069	$412,863	5.4%
2	FIRM GENERAL SERVICE	2,076,428	2,076,428	2,984,424	3,230,831	246,408	8.3%
3	FIRM CONTRACT SERVICE	641,741	641,741	225,126	225,126	0	0.0%
4	ELLSWORTH AIR FORCE BASE	550,146	550,146	35,249	35,249	0	0.0%
5	INTERRUPTIBLE	110,220	110,220	31,956	33,179	1,223	3.8%
6	INTERRUPTIBLE TRANSPORT	889,088	889,088	315,410	323,169	7,759	2.5%
7	TOTAL	7,303,382	7,303,382	$11,275,371	$11,943,624	$668,253	5.9%

Source:
Line 1 - 5: Exhibit____(MCB-5) Schedule 2, 3, and 4

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
1	CUSTOMER CHARGE	$7.60	$7.60
2	ALL DEKATHERMS	$1.43500	$1.57100
3	PGA	$6.97600	$6.97600

Rate 600 **RESIDENTIAL**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
4	0	$7.60	$7.60	$0.00	0.0%
5	1	16.02	16.15	0.14	0.8%
6	2	24.43	24.70	0.27	1.1%
7	3	32.84	33.25	0.41	1.2%
8	4	41.25	41.79	0.54	1.3%
9	5	49.66	50.34	0.68	1.4%
10	6	58.07	58.89	0.82	1.4%
11	7	66.48	67.43	0.95	1.4%
12	8	74.89	75.98	1.09	1.5%
13	9	83.30	84.53	1.22	1.5%
14	10	91.71	93.07	1.36	1.5%
15	12	108.54	110.17	1.63	1.5%
16	15	133.77	135.81	2.04	1.5%
17	20	175.82	178.54	2.72	1.5%
18	25	217.88	221.28	3.40	1.6%
19	30	259.93	264.01	4.08	1.6%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	15.4	136.73	138.83	2.09	1.5%
FEB	12.9	115.77	117.53	1.75	1.5%
MAR	10.9	99.00	100.48	1.48	1.5%
APR	8.7	80.55	81.74	1.18	1.5%
MAY	5.6	45.73	46.50	0.76	1.7%
JUN	3.1	30.18	30.60	0.42	1.4%
JUL	2.2	25.89	26.19	0.30	1.2%
AUG	1.6	20.44	20.66	0.22	1.1%
SEP	2.0	22.32	22.59	0.27	1.2%
OCT	3.7	35.94	36.45	0.50	1.4%
NOV	7.4	61.65	62.65	1.01	1.6%
DEC	11.4	90.86	92.41	1.55	1.7%
TOTAL	84.9	$765.07	$776.61	$11.55	1.5%

AVERAGE MONTHLY USE = 7.0 DekaTherms

Source:
Exhibit (MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
20	CUSTOMER CHARGE	$10.04	$10.65
21	ALL DEKATHERMS	$1.07810	$1.17500
22	PGA	$6.97600	$6.97600

Rate 700 **SMALL METER FIRM GENERAL SERVICE**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
23	0	10.04	10.65	$0.61	6.1%
24	5	50.31	51.40	1.09	2.2%
25	10	90.58	92.16	1.58	1.7%
26	15	130.85	132.91	2.06	1.6%
27	20	171.12	173.67	2.55	1.5%
28	30	251.66	255.18	3.52	1.4%
29	40	332.20	336.69	4.48	1.3%
30	50	412.74	418.20	5.45	1.3%
31	60	493.28	499.71	6.42	1.3%
32	70	573.82	581.22	7.39	1.3%
33	80	654.37	662.73	8.36	1.3%
34	90	734.91	744.24	9.33	1.3%
35	100	815.45	825.75	10.30	1.3%
36	150	1,218.15	1,233.30	15.14	1.2%
37	200	1,620.86	1,640.85	19.99	1.2%
38	250	2,023.56	2,048.40	24.83	1.2%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	27.9	234.75	238.06	3.31	1.4%
FEB	24.5	207.36	210.35	2.98	1.4%
MAR	21.0	179.17	181.82	2.64	1.5%
APR	14.1	123.60	125.57	1.97	1.6%
MAY	7.9	73.66	75.04	1.37	1.9%
JUN	4.2	43.86	44.88	1.02	2.3%
JUL	3.0	34.20	35.10	0.90	2.6%
AUG	2.5	30.17	31.02	0.85	2.8%
SEP	2.6	30.98	31.84	0.86	2.8%
OCT	4.5	46.28	47.33	1.04	2.3%
NOV	12.2	108.30	110.09	1.79	1.7%
DEC	19.8	169.51	172.04	2.53	1.5%
TOTAL	144.2	$1,281.85	$1,303.12	$21.27	1.7%

39

AVERAGE MONTHLY USE = 12.0 DekaTherms

Source:
Exhibit (MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
40	CUSTOMER CHARGE	$20.08	$21.29
41	ALL DEKATHERMS	$1.07810	$1.17500
42	PGA	$6.97600	$6.97600

Rate 701 **LARGE METER FIRM GENERAL SERVICE**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
43	0	20.08	21.29	$1.22	6.1%
44	5	60.35	62.05	1.70	2.8%
45	10	100.62	102.80	2.19	2.2%
46	15	140.89	143.56	2.67	1.9%
47	20	181.16	184.31	3.15	1.7%
48	30	261.70	265.82	4.12	1.6%
49	40	342.24	347.33	5.09	1.5%
50	50	422.78	428.84	6.06	1.4%
51	60	503.32	510.35	7.03	1.4%
52	70	583.86	591.86	8.00	1.4%
53	80	664.40	673.37	8.97	1.3%
54	90	744.94	754.88	9.94	1.3%
55	100	825.49	836.39	10.91	1.3%
56	150	1,228.19	1,243.94	15.75	1.3%
57	200	1,630.90	1,651.49	20.60	1.3%
58	250	2,033.60	2,059.04	25.44	1.3%
59	300	2,436.31	2,466.59	30.29	1.2%
60	350	2,839.01	2,874.14	35.13	1.2%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	197.7	1,612.37	1,632.74	$20.37	1.3%
FEB	172.1	1,406.19	1,424.08	$17.89	1.3%
MAR	154.1	1,261.21	1,277.36	$16.15	1.3%
APR	118.8	976.90	989.63	$12.73	1.3%
MAY	79.2	657.96	666.85	$8.89	1.4%
JUN	55.2	464.66	471.23	$6.57	1.4%
JUL	41.8	356.74	362.00	$5.27	1.5%
AUG	35.2	303.58	308.21	$4.63	1.5%
SEP	36.1	310.83	315.54	$4.71	1.5%
OCT	59.0	495.27	502.20	$6.93	1.4%
NOV	104.5	861.73	873.07	$11.34	1.3%
DEC	151.6	1,241.08	1,256.98	$15.91	1.3%
TOTAL	1,205.3	$9,948.51	$10,079.90	$131.39	1.3%

61

AVERAGE MONTHLY USE = 100.1 DekaTherms

Source:
Exhibit (MCB-5)

Montana-Dakota Utilities
South Dakota Gas
Residential Rates
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	CHANGE AMOUNT
	Small Meter									
	Residential - Rate 600									
1		ALL	DekaTherms	3,048,371	3,048,371	$ 1.43500	$ 1.57100	4,374,412	4,788,991	414,578
2										
3			Daily Charge			$ 0.25	$ 0.25			
4		CUSTOMER CHARGE	BILL	437,509	437,509	7.60	7.60	3,326,891	3,326,891	0
5										
6		PURCHASED GAS ADJUSTMENT				0.00000	0.00000			
7		SUB TOTAL	DekaTherms	3,048,371	3,048,371			7,701,304	8,115,882	414,578
8										
9	Residential Rate Unbilled Normalization									
10										
11		ALL	DekaTherms	(66,559)	(66,559)	1.43500	1.57100	(95,512)	(104,564)	(9,052)
12										
13		CUSTOMER CHARGE	BILL	0	0	7.60	7.60	0	0	0
14										
15		SUB TOTAL	DekaTherms	(66,559)	(66,559)			(95,512)	(104,564)	(9,052)
16										
17	Residential Rate Weather									
18										
19		ALL	DekaTherms	53,947	53,947	1.43500	1.57100	77,414	84,751	7,337
20										
21		CUSTOMER CHARGE	BILL	0	0	7.60	7.60	0	0	0
22										
23		PURCHASED GAS ADJUSTMENT				0.00000	0.00000			
24		SUB TOTAL	DekaTherms	53,947	53,947			77,414	84,751	7,337
25										
26	**TOTAL RESIDENTIAL - RATE 600**			**3,035,759**	**3,035,759**			**$ 7,683,206**	**$ 8,096,069**	**$ 412,863**
27										
28										

Montana-Dakota Utilities
South Dakota - Gas
Firm General Service Rates
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	CHANGE AMOUNT
	Small Meter									
	Firm General Service - Rate 700									
1		ALL	DekaTherms	505,166	505,166	$ 1.07810	$ 1.17500	544,619	593,570	48,951
2										
3			Daily Charge			$ 0.33	$ 0.35			
4		CUSTOMER CHARGE	BILL	42,548	42,548	10.04	10.65	427,076	452,959	25,883
5										
6										
7		SUB TOTAL	DekaTherms	505,166	505,166			971,695	1,046,529	74,834
8										
9	SMFG Rate Unbilled Normalization									
10										
11		ALL	DekaTherms	(13,887)	(13,887)	1.07810	1.17500	(14,972)	(16,317)	(1,346)
12										
13		CUSTOMER CHARGE	BILL	0	0	10.04	10.65	0	0	0
14										
15		SUB TOTAL	DekaTherms	(13,887)	(13,887)			(14,972)	(16,317)	(1,346)
16										
17	SMFG Rate Weather Normalization									
18										
19		ALL	DekaTherms	7,985	7,985	1.07810	1.17500	8,608	9,382	774
20										
21		CUSTOMER CHARGE	BILL	0	0	10.04	10.65	0	0	0
22										
23		SUB TOTAL		7,985	7,985			8,608	9,382	774

Montana-Dakota Utilities
South Dakota - Gas
Firm General Service Rates
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	CHANGE AMOUNT
24										
25	Reclassify Rate 71 as Rate 70									
26										
27		ALL	DekaTherms	9,941	9,941	1.07810	1.17500	10,717	11,681	963
28										
29		CUSTOMER CHARGE	BILL	0	0	10.04	10.65	0	0	0
30										
31		SUB TOTAL - PER BOOKS		9,941	9,941			10,717	11,681	963
32										
33	**TOTAL FIRM GENERAL SERVICE - RATE 700**			**509,204**	**509,204**			**976,049**	**1,051,274**	**$ 75,225**
34										
35	**Lage Meter**									
36	**Firm General Service - Rate 701**									
37										
38										
39		ALL	DekaTherms	1,575,717	1,575,717	$ 1.07810	$ 1.17500	1,698,780	1,851,467	152,687
40										
41			Daily Charge			$ 0.66	$ 0.70	per day		
42		CUSTOMER CHARGE	BILL	15,878	15,878	20.08	21.29	318,751	338,069	19,318
43										
44										
45		SUB TOTAL		1,575,717	1,575,717			2,017,531	2,189,537	172,005
46										
47	LMFG Rate Unbilled Normalization									
48										
49		ALL	DekaTherms	(29,443)	(29,443)	1.07810	1.17500	(31,742)	(34,596)	(2,853)
50										
51		CUSTOMER CHARGE	BILL	0	0	20.08	21.29	0	0	0
52										
53		SUB TOTAL - PER BOOKS		(29,443)	(29,443)			(31,742)	(34,596)	(2,853)
54										
55	LMFG Rate Weather Normalization									
56										
57		ALL	DekaTherms	20,950	20,950	1.07810	1.17500	22,586	24,616	2,030
58										
59		CUSTOMER CHARGE	BILL	0	0	20.08	21.29	0	0	0
60										
61										
62		SUB TOTAL		20,950	20,950			22,586	24,616	2,030
63										
64	**TOTAL FIRM GENERAL SERVICE - RATE 701**			**1,567,224**	**1,567,224**			**2,008,375**	**2,179,557**	**171,182**
65										
66	**TOTAL FIRM GENERAL SERVICE**			**2,076,428**	**2,076,428**			**$ 2,984,424**	**$3,230,831**	**$ 246,408**

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	TYPE OF CHARGE	UNIT	>--------- QUANTITY ---------< PRESENT	PROPOSED	>-- RATE ($/UNIT) --< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>-- INCREASE ---< AMOUNT	PERCENT
	Firm Contract Service - Rate 702										
1		MIN BILLS	BILL			150.00	150.00				
2		MIN BILLS									
3		ALL	DekaTherms	639,787	639,787	0.34800	0.34800	222,646	222,646	0	
4											
5	CUSTOMER CHARGE & MINNUM		BILL	12	12	150.00	150.00	1,800	1,800	0	
6											
7	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
8		SUBTOTAL	DekaTherms	639,787	639,787			224,446	224,446	0	
9											
10	Firm Contract Service - Rate 702 - Weather Normalization										
11											
12		MIN BILLS	BILL			150.00	150.00				
13		MIN BILLS									
14		ALL	DekaTherms	1,954	1,954	0.34800	0.34800	680	680	0	
15											
16	CUSTOMER CHARGE & MINNUM		BILL	0	0	150.00	150.00	0	0	0	
17											
18	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
19		SUBTOTAL	DekaTherms	1,954	1,954			680	680	0	
20											
21	**TOTAL - Firm Contract Service - Rate 702**			**641,741**	**641,741**			**$ 225,126**	**$ 225,126**	**$ -**	**0.0%**
22											

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
23	**Ellsworth Air Force Base - Rate 641**											
24												
25			MIN BILLS	BILL			95.00	95.00				
26			MIN BILLS									
27			ALL	DekaTherms	537,378	537,378	0.06200	0.06200	33,317	33,317	0	
28												
29	CUSTOMER CHARGE & MINNUM			BILL	12	12	95.00	95.00	1,140	1,140	0	
30												
31	PURCHASED GAS ADJUSTMENT						0.00000	0.00000	0	0	0	
32			SUBTOTAL	DekaTherms	537,378	537,378			34,457	34,457	0	
33												
34	EAFB - Weather Normalization											
35												
36			MIN BILLS	BILL			95.00	95.00				
37			MIN BILLS									
38			ALL	DekaTherms	12,768	12,768	0.06200	0.06200	792	792	0	
39												
40	CUSTOMER CHARGE & MINNUM			BILL	0	0	95.00	95.00	0	0	0	
41												
42	PURCHASED GAS ADJUSTMENT						0.00000	0.00000	0	0	0	
43			SUBTOTAL	DekaTherms	12,768	12,768			792	792	0	
44												
45	**TOTAL - ELLSWORTH AIR FORCE BASE - RATE 641**				**550,146**	**550,146**			**$ 35,249**	**$ 35,249**	**$ -**	**0.0%**
46												

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
47	**Small Interruptible - Rate 71**										
48											
49		MIN BILLS	BILL			50.00	50.00				
50											
51		ALL	DekaTherms	35,076	35,076	0.45300	0.45300	15,889	15,889	0	
52											
53		CUSTOMER CHARGE & MINNUM	BILL	119	119	50.00	50.00	5,950	5,950	0	
54											
55		PURCHASED GAS ADJUSTMENT				0.00000	0.00000	0	0	0	
56		SUBTOTAL	DekaTherms	35,076	35,076			21,839	21,839	0	
57											
58	Small Interruptible Rate Unbilled Normalization										
59											
60		ALL THERMS	DekaTherms	(2,774)	(2,774)	0.45300	0.45300	(1,257)	(1,257)	0	
61											
62											
63		CUSTOMER CHARGE & MINNUM	BILL	0	0	50.00	50.00	0	0	0	
64											
65		SUB TOTAL	DekaTherms	(2,774)	(2,774)			(1,257)	(1,257)	0	
66											
58	Small Interruptible - Rate 71 - Weather Normalization										
59											
60		MIN BILLS	BILL			50.00	50.00				
61											
62		ALL	DekaTherms	531	531	0.45300	0.45300	241	241	0	
63											
64		CUSTOMER CHARGE & MINNUM	BILL	0	0	50.00	50.00	0	0	0	
65											
66		PURCHASED GAS ADJUSTMENT				0.00000	0.00000	0	0	0	
67		SUBTOTAL	DekaTherms	531	531			241	241	0	
68											
69	Small Interruptible - Rate 71 - Reclassify as Rate 70										
70											
71		MIN BILLS	BILL			50.00	50.00				
72											
73		ALL	DekaTherms	(9,941)	(9,941)	0.45300	0.45300	(4,503)	(4,503)	0	
74											
75		CUSTOMER CHARGE & MINNUM	BILL	(30)	(30)	50.00	50.00	(1,500)	(1,500)	0	
76											
77		PURCHASED GAS ADJUSTMENT				0.00000	0.00000	0	0	0	
78		SUBTOTAL	DekaTherms	(9,941)	(9,941)			(6,003)	(6,003)	0	
79		RATE 71 FLEX ADJUSTMENT						(421)	(421)	0	
80	**TOTAL - SMALL INTERRUPTIBLE - RATE 71**			**22,892**	**22,892**			**14,399**	**14,399**	**0**	**0.0%**

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
81												
82	**Large Interruptible - Rate 85**											
83												
84			MIN BILLS	BILL			150.00	175.00				
85			MIN BILLS									
86			ALL	DekaTherms	86,205	86,205	0.17700	0.18700	15,258	16,120	862	
87												
88	CUSTOMER CHARGE & MINNUM			BILL	14	14	150.00	175.00	2,100	2,450	350	
89												
90	PURCHASED GAS ADJUSTMENT						0.00000	0.00000	0	0	0	
91			SUBTOTAL	DekaTherms	86,205	86,205			17,358	18,570	1,212	
92												
93	Large Interruptible - Rate 85 - Weather Normalization											
94												
95			MIN BILLS	BILL			150.00	175.00				
96			MIN BILLS									
97			ALL	DekaTherms	1,123	1,123	0.17700	0.18700	199	210	11	
98												
99	CUSTOMER CHARGE & MINNUM			BILL	0	0	150.00	175.00	0	0	0	
100												
101	PURCHASED GAS ADJUSTMENT						0.00000	0.00000	0	0	0	
102			SUBTOTAL	DekaTherms	1,123	1,123			199	210	11	
103												
104	**TOTAL - LARGE INTERRUPTIBLE - RATE 85**				**87,328**	**87,328**			**17,557**	**18,780**	**$ 1,223**	**7.0%**
105												
106	**TOTAL - INTERRUPTIBLE**				**110,220**	**110,220**			**$ 31,956**	**$ 33,179**	**$ 1,223**	**3.8%**
107												

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
108	**Small Interruptible Transportion - Rate 81**											
109												
110			MIN BILLS	BILL			125.00	125.00				
111			MIN BILLS									
112			ALL	DekaTherms	354,602	354,602	0.45300	0.45300	160,635	160,635	0	
113												
114	CUSTOMER CHARGE & MINNUM			BILL	336	336	125.00	125.00	42,000	42,000	0	
115												
116	PURCHASED GAS ADJUSTMENT						0.00000	0.00000	0	0	0	
117			SUBTOTAL	DekaTherms	354,602	354,602			202,635	202,635	0	
118												
119	Small Interruptible Transportion - Rate 81 - Weather Normalization											
120												
121			MIN BILLS	BILL			125.00	125.00				
122			MIN BILLS									
123			ALL	DekaTherms	6,226	6,226	0.45300	0.45300	2,820	2,820	0	
124												
125	CUSTOMER CHARGE & MINNUM			BILL	0	0	125.00	125.00	0	0	0	
126												
127	PURCHASED GAS ADJUSTMENT						0.00000	0.00000	0	0	0	
128			SUBTOTAL	DekaTherms	6,226	6,226			2,820	2,820	0	
129												
130	Small Interruptible Transportation - Rate 81 - Cut Out of Service											
131												
132			MIN BILLS	BILL			125.00	125.00				
133			MIN BILLS									
134			ALL	DekaTherms	(5,282)	(5,282)	0.45300	0.45300	(2,393)	(2,393)	0	
135												
136	CUSTOMER CHARGE & MINNUM			BILL	(2)	(2)	125.00	125.00	(250)	(250)	0	
137												
138	PURCHASED GAS ADJUSTMENT						0.00000	0.00000	0	0	0	
139			SUBTOTAL	DekaTherms	(5,282)	(5,282)			(2,643)	(2,643)	0	
140												

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
141	CUSTOMER BILLED INCORRECTLY		Customer ID 41								
142											
143		MIN BILLS	BILL			125.00	125.00				
144		MIN BILLS									
145		ALL	DekaTherms	(10,225)	(10,225)	0.45300	0.45300	(4,632)	(4,632)	0	
146											
147	CUSTOMER CHARGE & MINNUM		BILL	(1)	(1)	125.00	125.00	(125)	(125)	0	
148											
149	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
150		SUBTOTAL	DekaTherms	(10,225)	(10,225)			(4,757)	(4,757)	0	
151											
152	Small Interruptible Transportation - Rate 82 - Reclassify as Rate 81										
153											
154		MIN BILLS	BILL			125.00	125.00				
155		MIN BILLS									
156		ALL	DekaTherms	10,403	10,403	0.45300	0.45300	4,713	4,713	0	
157											
158	CUSTOMER CHARGE & MINNUM		BILL	24	24	125.00	125.00	3,000	3,000	0	
159											
160	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
161		SUBTOTAL	DekaTherms	10,403	10,403			7,713	7,713	0	
162	RATE 81 FLEX ADJUSTMENT		Customer ID 264					(2,608)	(2,608)	0	
163	RATE 81 FLEX ADJUSTMENT		Customer ID 105					(1,555)	(1,555)	0	
164	**TOTAL - SMALL INTERRUPTIBLE TRANSPORTATION - RATE 81**			**355,724**	**355,724**			**$ 201,605**	**$ 201,605**	**$ -**	**0.0%**

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
165											
166	**Large Interruptible Transportation - Rate 82**										
167											
168		MIN BILLS	BILL			200.00	225.00				
169		MIN BILLS									
170		ALL	DekaTherms	613,766	613,766	0.17700	0.18700	108,637	114,774	6,138	
171											
172	CUSTOMER CHARGE & MINNUM		BILL	139	139	200.00	225.00	27,800	31,275	3,475	
173											
174	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
175		SUBTOTAL	DekaTherms	613,766	613,766			136,437	146,049	9,613	
176											
177	Large Interruptible Transportion - Customer ID 41 - Weather Normalization										
178											
179		MIN BILLS	BILL			200.00	225.00				
180		MIN BILLS									
181		ALL	DekaTherms	1,079	1,079	0.17700	0.18700	191	202	11	
182											
183	CUSTOMER CHARGE & MINNUM		BILL	0	0	200.00	225.00	0	0	0	
184											
185	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
186		SUBTOTAL	DekaTherms	1,079	1,079			191	202	11	
187											
188	CUSTOMER BILLED INCORRECTLY		Customer ID 41								
189											
190		MIN BILLS	BILL			200.00	225.00				
191		MIN BILLS									
192		ALL	DekaTherms	(10,225)	(10,225)	0.17700	0.18700	(1,810)	(1,912)	(102)	
193											
194	CUSTOMER CHARGE & MINNUM		BILL	(1)	(1)	200.00	225.00	(200)	(225)	(25)	
195											
196	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
197		SUBTOTAL	DekaTherms	(10,225)	(10,225)			(2,010)	(2,137)	(127)	
198											

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
199	Large Interruptible Transportation - Rate 82 - Cut Out of Service										
200											
201		MIN BILLS	BILL			200.00	225.00				
202		MIN BILLS									
203		ALL	DekaTherms	(60,853)	(60,853)	0.17700	0.18700	(10,771)	(11,380)	(609)	
204											
205	CUSTOMER CHARGE & MINNUM		BILL	(17)	(17)	200.00	225.00	(3,400)	(3,825)	(425)	
206											
207	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
208		SUBTOTAL	DekaTherms	(60,853)	(60,853)			(14,171)	(15,205)	(1,034)	
209											
210	Large Interruptible Transportation - Rate 82 - Reclassify as Rate 81										
211											
212		MIN BILLS	BILL			200.00	225.00				
213		MIN BILLS									
214		ALL	DekaTherms	(10,403)	(10,403)	0.17700	0.18700	(1,841)	(1,945)	(104)	
215											
216	CUSTOMER CHARGE & MINNUM		BILL	(24)	(24)	200.00	225.00	(4,800)	(5,400)	(600)	
217											
218	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
219		SUBTOTAL	DekaTherms	(10,403)	(10,403)			(6,641)	(7,345)	(704)	
220											
221	**TOTAL - LARGE INTERRUPTIBLE TRANSPORTATION - RATE 82**			**533,364**	**533,364**			**$ 113,805**	**$ 121,564**	**$ 7,759**	**6.8%**
222											
223	**TOTAL - INTERRUPTIBLE TRANSPORTATION**			**889,088**	**889,088**			**$ 315,410**	**$ 323,169**	**$ 7,759**	**2.5%**

Montana-Dakota Utilities
South Dakota - Gas
Interruptible and Transportation Service
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
	Firm Contract Service - Rate 702										
1		MIN BILLS	BILL			150.00	150.00				
2											
3		ALL	DekaTherms	641,741	641,741	0.34800	0.34800	223,326	223,326	0	
4											
5		CUSTOMER CHARGE & MINNUM	BILL	12	12	150.00	150.00	1,800	1,800	0	
6											
7		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			5.24100	5.24100	3,363,365	3,363,365	0	
8	**TOTAL - Firm Contract Service - Rate 702**			**641,741**	**641,741**			**$ 3,588,490**	**$ 3,588,490**	**$ -**	**0.0%**
9											
10	**Ellsworth Air Force Base**										
11											
12		MIN BILLS	BILL			95.00	95.00				
13											
14		ALL	DekaTherms	550,146	550,146	0.06200	0.06200	34,109	34,109	0	
15											
16		CUSTOMER CHARGE & MINNUM	BILL	12	12	95.00	95.00	1,140	1,140	0	
17											
18		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			3.95700	3.95700	2,176,928	2,176,928	0	
19	**TOTAL - Ellsworth Air Force Base**			**550,146**	**550,146**			**$ 2,212,177**	**$ 2,212,177**	**$ -**	**0.0%**
20											
21	**Small Interruptible - Rate 71**										
22											
23		MIN BILLS	BILL			50.00	50.00				
24											
25		ALL	DekaTherms	22,892	22,892	0.45300	0.45300	10,370	10,370	0	
26											
27		CUSTOMER CHARGE & MINNUM	BILL	119	119	50.00	50.00	5,950	5,950	0	
28											
29		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			5.24100	5.24100	119,977	119,977	0	
30	**TOTAL - SMALL INTERRUPTIBLE - RATE 71**			**22,892**	**22,892**			**$ 136,297**	**$ 136,297**	**$ -**	**0.0%**
31											

Source: Exhibit____(MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Interruptible and Transportation Service
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	QUANTITY PRESENT	QUANTITY PROPOSED	RATE ($/UNIT) PRESENT	RATE ($/UNIT) PROPOSED	REVENUES (IN $) PRESENT	REVENUES (IN $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
32	**Large Interruptible - Rate 85**										
33											
34		MIN BILLS	BILL			150.00	175.00				
35											
36		ALL	DekaTherms	87,328	87,328	0.17700	0.18700	15,457	16,330	873	
37											
38		CUSTOMER CHARGE & MINNUM	BILL	14	14	150.00	175.00	2,100	2,450	350	
39											
40		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			4.00200	4.00200	349,487	349,487	0	
41	**TOTAL - LARGE INTERRUPTIBLE - RATE 85**			**87,328**	**87,328**			**$ 367,044**	**$ 368,267**	**$ 1,223**	**0.3%**
42											
43	**Small Interruptible Transportion - Rate 81**										
44											
45		MIN BILLS	BILL			125.00	125.00				
46											
47		ALL	DekaTherms	355,724	355,724	0.45300	0.45300	161,143	161,143	0	
48											
49		CUSTOMER CHARGE & MINNUM	BILL	357	357	125.00	125.00	44,625	44,625	0	
50											
51		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			5.24100	5.24100	1,864,349	1,864,349	0	
52	**TOTAL - SMALL INTERRUPTIBLE TRANSPORTATION - RATE 81**			**355,724**	**355,724**			**$ 2,070,117**	**$ 2,070,117**	**$ -**	**0.0%**
53											
54											
55	**Large Interruptible Transportation - Rate 82**										
56											
57		MIN BILLS	BILL			200.00	225.00				
58											
59		ALL	DekaTherms	533,364	533,364	0.17700	0.18700	94,405	99,739	5,334	
60											
61		CUSTOMER CHARGE & MINNUM	BILL	97	97	200.00	225.00	19,400	21,825	2,425	
62											
63		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			4.00200	4.00200	2,134,523	2,134,523	0	
64	**TOTAL - LARGE INTERRUPTIBLE TRANSPORTATION - RATE 82**			**533,364**	**533,364**			**$ 2,248,328**	**$ 2,256,087**	**$ 7,759**	**0.3%**
65											
66	**TOTAL - OTHER INTERRUPTIBLE and TRANSPORTATION**			**2,191,195**	**2,191,195**			**$ 10,622,454**	**$ 10,631,436**	**$ 8,982**	**0.1%**

Source: Exhibit____(MCB-5)

MDU PROPOSED NOTICE OF INCREASE TO CUSTOMERS

Change in Natural Gas Rates
Effective December 1, 2004

On June 7, 2004, Montana-Dakota Utilities Co. (Montana-Dakota) filed an application with the South Dakota Public Utilities Commission (Commission) for an increase in prices charged for natural gas service to our customers. Montana-Dakota requested an increase of approximately $1.3 million in additional revenues. Only non-gas related or distribution costs were a part of the filing. The primary reason for the rate filing was increased operating expenses driven largely by increases in labor and benefit costs. Montana-Dakota's non-gas rates were last increased in December 2003. On November 30, 2004, the Commission approved a natural gas rate increase in the amount of $669,549 to become effective December 1, 2004.

As a result of the change in rates approved by the Commission on November 30, 2004, the rates for the residential, firm general and large interruptible service customer classes will increase by 1.6 percent. A typical residential customer consuming 86 dekatherms (dk) annually would see an increase of approximately $0.97 per month.

The new rates shown below became effective with service rendered on and after December 1, 2004. The first bill you receive may be prorated, depending on your meter reading date. This means that any service provided prior to December 1, 2004 will be billed at the old rates, and any service provided on and after December 1, 2004 will be billed at the new rates included in this folder.

Residential Gas Service – Rate 60
Rate:

Basic Service Charge	$0.250 per day*
Distribution Delivery Charge	$1.571 per dk*
Cost of Gas	$8.571 per dk**

Minimum bill: Basic Service Charge

Firm General Gas Service – Rate 70
Rate:

Basic Service Charge:	
Meters rated under 500 cubic feet per hour	$0.350 per day*
Meters rated over 500 cubic feet per hour	$0.700 per day*
Distribution Delivery Charge	$1.175 per dk*
Cost of Gas	$8.571 per dk**

Minimum bill: Basic Service Charge

A Distribution Delivery Stabilization Mechanism (DDSM) is also applicable to gas service provided under Residential Rate 60 and Firm General Rate 70 bills issued October 1 through May 1. The DDSM is an adjustment designed to balance the fluctuations in weather affecting both customers and the Company during the winter heating season.

**All rates, including cost of gas, are effective with service rendered on and after*

December 1, 2004.

***On December 1, 2004, the Purchased Gas Adjustment (PGA), filed monthly with the Commission, has increased approximately $1.70 per dk for all customers. The PGA increases or decreases our retail prices based on our estimates of purchased gas costs for the month and adjustments for any over- or under-estimates of these costs in prior periods. The PGA mechanism is strictly a pass-through to our customers of costs imposed on Montana-Dakota by its gas suppliers. The PGA provides no mark-up or profit to Montana-Dakota. New cost of gas prices for residential and firm general natural gas service are shown in this folder and will become effective with service rendered on and after December 1, 2004.*

Other Rates Available:
Small Interruptible General Gas Service – Rate 71; Large Interruptible General Gas Service – Rate 85; Optional Seasonal General Gas Service – Rate 72; Transportation Service – Rates 81 and 82

NSF Check Charge:
A charge of $20.00 will be collected by the Company for each check charged back to the Company by a bank.

Seasonal Reconnect Charge:
Any customer who requests the reconnection of service at the same address within a 12-month period will be charged the Basic Service Charge applicable during the period while service was not in use or a minimum of $30.00. The minimum will be based on standard overtime rates for reconnection of service after normal business hours.

Payment:
Bills will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any unpaid balance existing on the immediate subsequent billing date.

Comparison of Residential Rate

Dk	Present Rate*	Proposed Rate*	Amount of Increase	% Increase
3	$37.62	$38.03	$0.41	1.09%
5	57.63	58.31	0.68	1.18%
10	107.66	109.02	1.36	1.26%
15	157.69	159.73	2.04	1.29%
18	187.71	190.16	2.45	1.31%
20	207.72	210.44	2.72	1.31%

For further information, applicable rates, rules and regulations are on file at Montana-Dakota's offices and are available for inspection upon request.

South Dakota 12/04

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	)))))	**ORDER GRANTING JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION NG04-004**

On June 7, 2004, Montana-Dakota Utilities Co. (MDU), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in its Black Hills service territory. The application seeks an increase in rates in the approximate amount of $1,281,417 or approximately 2.2%. On June 22, 2004, the Commission suspended the proposed schedule of rates for 90 days beyond June 7, 2004.

At its regularly scheduled meeting of June 22, 2004, the Commission found that pursuant to SDCL 49-1A-8, MDU shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 9, 2004. On July 15, 2004, Commission Staff advised the Commission that the suspension should have been for 90 days beyond July 7, 2004. On July 20, 2004, pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by MDU for 90 days beyond July 7, 2004.

The Commission set the matter for hearing for November 4 and 5, 2004, starting at 9:00 A.M., on November 4, 2004, in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota. On October 28, 2004, the Commission was informed that Commission Staff and MDU had reached a settlement agreement, so the hearing set for November 4 and 5, 2004, which was scheduled to hear the testimony of the parties was cancelled. On November 15, 2004, the Commission received a Joint Motion for Approval of Settlement Stipulation and Settlement Stipulation signed by all of the parties. On November 18, 2004, the Commission received Staff Memorandum Supporting Settlement Stipulation. Staff requested that the Commission consider the Settlement Agreement on November 30, 2004.

The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-18, 1-26-19, 49-34A-2, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-8.1, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-16, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-20, 49-34A-21, 49-34A-22, and 49-34A-23.

On November 30, 2004, the Commission heard from MDU and Commission Staff concerning the proposed Settlement Stipulation. After listening to the presentations, the Commission voted to grant the Joint Motion for Approval of Settlement Stipulation.

The tariff sheets approved by this order and effective for service rendered on and after December 1, 2004, are as follows:

Section No. 1
1st Revised Sheet No. 1, Canceling Original Sheet No. 1
1st Revised Sheet No. 1.1, Canceling Original Sheet No. 1.1

Section 3
9th Revised Sheet No. 1, Canceling 8th Revised Sheet No. 1
1st Revised Sheet No. 2, Canceling Original Sheet No. 2
1st Revised Sheet No. 11, Canceling Original Sheet No. 11
2nd Revised Sheet No. 13, Canceling 1st Revised Sheet No. 13
1st Revised Sheet No. 22.1, Canceling Original Sheet No. 22.1
1st Revised Sheet No. 26, Canceling Original Sheet No. 26

Section 5
1st Revised Sheet No. 1, Canceling Original Sheet No. 1
1st Revised Sheet No. 1.1, Canceling Original Sheet No. 1.1
1st Revised Sheet No. 1.2, Canceling Original Sheet No. 1.2
1st Revised Sheet No. 1.3, Canceling Original Sheet No. 1.3
1st Revised Sheet No. 1.4, Canceling Original Sheet No. 1.4
1st Revised Sheet No. 1.5, Canceling Original Sheet No. 1.5
1st Revised Sheet No. 1.6, Canceling Original Sheet No. 1.6
1st Revised Sheet No. 1.7, Canceling Original Sheet No. 1.7
1st Revised Sheet No. 1.8, Canceling Original Sheet No. 1.8
1st Revised Sheet No. 1.9, Canceling Original Sheet No. 1.9
1st Revised Sheet No. 1.10, Canceling Original Sheet No. 1.10
1st Revised Sheet No. 1.11, Canceling Original Sheet No. 1.11
1st Revised Sheet No. 1.12, Canceling Original Sheet No. 1.12
1st Revised Sheet No. 1.13, Canceling Original Sheet No. 1.13
1st Revised Sheet No. 1.14, Canceling Original Sheet No. 1.14
1st Revised Sheet No. 1.15, Canceling Original Sheet No. 1.15
1st Revised Sheet No. 1.16, Canceling Original Sheet No. 1.16
1st Revised Sheet No. 1.17, Canceling Original Sheet No. 1.17
1st Revised Sheet No. 1.18, Canceling Original Sheet No. 1.18
1st Revised Sheet No. 1.19, Canceling Original Sheet No. 1.19
1st Revised Sheet No. 24, Canceling Original Sheet No. 24

Section 6
1st Revised Sheet No. 5, Canceling Original Sheet No. 5
1st Revised Sheet No. 8, Canceling Original Sheet No. 8
Original Sheet No. 8.1
1st Revised Sheet No. 12, Canceling Original Sheet No. 12
1st Revised Sheet No. 13, Canceling Original Sheet No. 13
1st Revised Sheet No. 16, Canceling Original Sheet No. 16

It is therefore

ORDERED, that the Joint Motion for Approval of Settlement Stipulation is hereby granted. The Settlement Stipulation is incorporated by reference into this Decision and Order the same as if it had been set forth in its entirety herein.

Dated at Pierre, South Dakota, this 10th day of December, 2004.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 12/13/04

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

ROBERT K. SAHR, Chairman

GARY HANSON, Commissioner

JAMES A. BURG, Commissioner

RECEIVED
NOV 15 2004
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE NATURAL GAS RATES IN SOUTH DAKOTA	)	DOCKET NO. NG04-004

I. SETTLEMENT STIPULATION

On June 7, 2004, Montana-Dakota Utilities Co. ("Montana-Dakota") filed with the South Dakota Public Utilities Commission ("Commission") an application for approval to increase rates for natural gas service in the State of South Dakota for its Black Hills system. Montana-Dakota proposed an overall increase of $1,281,417. The Staff of the Commission ("Commission Staff") on October 19, 2004, filed its direct testimony supporting an overall increase for Montana-Dakota of $210,448.

The Commission Staff and Montana-Dakota (jointly the "Parties") held several negotiating sessions in an effort to arrive at a jointly acceptable resolution of this matter. As a result of the sessions, the Parties have been able to resolve all issues in this proceeding and have entered into this Settlement Stipulation ("Stipulation"), which, if accepted and ordered by the Commission, will determine rates to result from this proceeding.

II. PURPOSE

This Stipulation has been prepared and executed by the Parties for the sole purpose of resolving Docket No. NG04-004. The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Settlement Agreement, should not be viewed as precedent setting. In consideration of the mutual promises hereinafter set forth, the Parties agree as follows:

1. Upon execution of this Stipulation, the Parties shall immediately file this Stipulation with the Commission together with a joint motion requesting that the Commission issue an order approving this Stipulation in its entirety without condition or modification.

2. This Stipulation includes all terms of settlement and is submitted with the condition that in the event the Commission imposes any changes in or conditions to this Stipulation which are unacceptable to any party, this Stipulation shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding nor be used for any other purpose.

3. This Stipulation shall become binding upon execution by the Parties, provided however, that if this Stipulation does not become effective in accordance with Paragraph 2 above, it shall be null, void and privileged. This Stipulation is intended to relate only to the specific matters referred to herein; no party waives any claim or right which it may otherwise have with respect to any matter not

expressly provided for herein; no party shall be deemed to have approved, accepted, agreed or consented to any rate making principle, or any method of cost of service determination, or any method of cost allocation underlying the provisions of this Stipulation, or be prejudiced or bound thereby in any other current or future proceeding before the Commission. No party or representative thereof shall directly or indirectly refer to this Stipulation or that part of any order of the Commission referring to this Stipulation as precedent in any other current or future rate proceeding before the Commission.

4. The Parties to this proceeding stipulate that all prefiled testimony, exhibits, and workpapers be made a part of the record in this proceeding. The Parties understand that if this matter had not been settled, Montana-Dakota would have filed rebuttal testimony and the Commission Staff would have responded to certain of the positions contained in Montana-Dakota's rebuttal testimony.

5. It is understood that Commission Staff enters into this Stipulation for the benefit of Montana-Dakota's South Dakota customers affected by this docket.

III. ELEMENTS OF THE SETTLEMENT STIPULATION

1. Revenue Requirement

The Parties agree that Montana-Dakota's attached rate schedules are designed to produce annual increases in base rate levels (excluding purchased gas cost adjustment and sales taxes) of $669,549 annually for retail natural gas service in the Company's Black Hills service area in the State of South Dakota. The parties agree to an overall rate of return of 8.917%.

2. Tariffs

The increase will be allocated on an equal percentage basis to the Residential, Firm General Service and Large Interruptible rate classes resulting in an increase of 1.6% to each of the affected rate classes. The Tariffs reflect the following basic service charges with the remainder of the applicable revenue increase collected through the Distribution Delivery Charges:

Rate Class	Base Rate
Residential	$0.25 per day
Firm General	
Meters < 500 cubic ft./hour	$0.35 per day
Meters > 500 cubic ft./hour	$0.70 per day
Air Force	$95.00 per month
Small Interruptible Sales	$50.00 per month
Small Interruptible Transport	$125.00 per month
Large Interruptible Sales	$175.00 per month
Large Interruptible Transport	$225.00 per month

3. Implementation of Rates

The revised rate schedules shall be implemented with service rendered on and after December 1, 2004, with bills prorated so that usage prior to December 1, 2004 is billed at the previous rates and usage on and after December 1, 2004, is billed at the new rates.

4. Conclusion

This Stipulation is entered into this 15 day of November, 2004.

Montana-Dakota Utilities Co.

BY: _____

South Dakota Public Utilities Commission

BY: Karen E. Cremer

Mr. Brett M. Koenecke
Attorney
May, Adam, Gerdes and Thompson
503 South Pierre Street
P.O. Box 160
Pierre, SD 57501

DATED: 11/15/04

Karen E. Cremer
Attorney
State Capitol Building
500 East Capitol Building
Pierre, SD 57501-5070

DATED: 11/16/04