KC/DJ
KS/MB/MY

NG02 011

NG02-011

DOCKET NO. _____

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

Public Utilities Commission of the State of South Dakota

DATE		MEMORANDA
12/30	02	Filed and Docketed;
1/2	03	Weekly Filing;
1/28	03	Order of Assessment of Filing Fee and Suspension of Imposition of Tariff;
2/6	03	Contract between Chesapeake and SDPUC;
3/20	03	Order for and Notice of Procedural Schedule and Hearing;
4/8	03	Order Extending Suspension of Imposition of Tariff;
4/22	03	Testimony of Martin C. Bettmann, Basil L. Copeland Jr., Michele M. Farris, David A. Jacobson, Keith A. Sexson, Robert B. Towers
4/30	03	MDU's Motion to Continue and Reschedule the Hearing;
5/7	03	MDU's Interrogatories and Requests for Production to Commission Staff;
5/16	03	Order Continuing Hearing;
5/22	03	MDU's Motion to Extend Deadline for Rebuttal Testimony;
6/5	03	Order for and Notice of Hearing;
6/6	03	MDU Rebuttal Testimony;
6/10	03	Order Granting Motion to Extend Deadline for Rebuttal Testimony;
6/12	03	MDU's Third Request for Confidential Treatment of Information;
6/13	03	Motion to Continue and Reschedule the Hearing and Further Suspend Rates;
7/1	03	Order Granting Motion to Continue and Reschedule the Hearing & Further Suspend Rates;
10/27	03	Settlement Stipulation;
10/27	03	Staff Memorandum Supporting Settlement Stipulation;
10/27	03	Joint Motion for Approval of Settlement Stipulation;
11/13	03	Order for and Notice of Hearing to Consider Settlement Stipulation;
12/5	03	Gas Tariff;
12/17	03	Decision and Order Approving Settlement Stipulation;
12/17/03		Docket Closed.
12/23/03		Final Tariff.

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

MR DONALD R BALL
DIRECTOR OF REGULATORY AFFAIRS
MONTANA-DAKOTA UTILITIES CO
400 NORTH FOURTH STREET
BISMARCK ND 58501

MR DOUGLAS W SCHULZ
SENIOR ATTORNEY
MDU RESOURCES GROUP INC
PO BOX 5650
BISMARCK ND 58506-5650

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DUNKIRK MD 20754

MR BASIL COPELAND
14619 CORVALLIS ROAD
MAUMELLE AR 72118

MONTANA-DAKOTA UTILITIES CO.

DOCKET NO. NG02-____

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

NG02-011

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

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

December 27, 2002

RECEIVED
DEC 30 2002
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

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

Re: General Natural Gas Rate Application
Docket No. NG02-___

Dear Ms. Elofson:

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 expenses such as operating and maintenance expenses, depreciation, and taxes other than income taxes and an increase in the investment in facilities used to provide natural gas service to customers.

In spite of cost control efforts, cost-of-service increases have caused current rates to be inadequate in compensating the company for operating its South Dakota natural gas distribution system. Montana-Dakota's last general rate

increase in South Dakota was in late 1994 (Docket NG94-012). Since then, the Consumer Price Index has increased by about 21 percentage points.

Montana-Dakota proposes a total annual increase of $2,173,380, or 5.8%, based on a 2003 projected test year. The proposed change in rates will affect customer classes as follows: Residential, 5.8% and Firm General Service, 8.4%. The proposed increase for a residential customer will average about $2.50 per month or about $30.00 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.

With this filing, Montana-Dakota also proposes to own all service lines on a prospective basis. This change will apply to all new and replacement service lines subject to appropriate extension policy provisions.

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 40,800 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
Director of 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
Senior Attorney
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
Director of 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	1
2	Preliminary Statement	1
3	Rate Schedules	1-30
4	List of Contracts with Deviations	1
5	Rules	1-34
6	Sample Forms	1-24

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 $37,186,594
Proposed Rates $39,359,974
Approximate annual reduction in revenue .....
Approximate annual increase in revenue $2,173,380

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		40,800	$2,173,380		

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
Director of Regulatory Affairs
(Name and Title)

SD-20:10:13:26

On December 30, 2002, 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. NG02-__

* * * *

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	
15th Revised Sheet No. 1	Table of Contents
Section 2	
5th Revised Sheet No. 1	Preliminary Statement
Section 3	
19th Revised Sheet No. 1	Residential Gas Service Rate 60
2nd Revised Sheet No. 5	Ellsworth Air Force Base Rate 64
1st Revised Sheet No. 7	East River Natural Gas System General Services Rate 66
2nd Revised Sheet No. 11	Firm General Gas Service Rate 70
1st Revised Sheet No. 12	Small Interruptible General Gas Service Rate 71
2nd Revised Sheet No. 13	Optional Seasonal General Gas Service Rate 72
1st Revised Sheet No. 22	Transportation Service Rates 81, 82, 84
1st Revised Sheet No. 26	Large Interruptible General Gas Service Rate 85
3rd Revised Sheet No. 29	Purchased Gas Cost Adjustment Rate 88
4th Revised Sheet No. 30	East River Natural Gas System Purchased Gas Cost Adjustment Rate 89

Section 4

9th Revised Sheet No. 1	List of Gas Contracts with Deviations

Section 5

1st Revised Sheet No. 1	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 No. 19	Interruptible Gas Service Extension Policy Rate 119
1st Revised Sheet No. 20	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. 25	New Installation, Replacement, Relocation and Repair of Company-Owned Gas Service Lines Rate 125
Original Sheet No. 34	Rule and Policies for Implementing Master Metering Restrictions Rate 134

Section 6

4th Revised Sheet No. 1	Consumer's Deposit Receipt
4th Revised Sheet No. 2	New Customer Application Card – Residential Service
2nd Revised Sheet No. 3	Gas Meter Order
2nd Revised Sheet No. 4	Consumer Billing Adjustment Form
6th Revised Sheet No. 5	Standard Customer Bill Form
4th Revised Sheet No. 6	Disconnect Notice
1st Revised Sheet No. 7	Application for Interruptible Natural Gas Service
2nd Revised Sheet No. 8	Customer Information Booklet
Original Sheet No. 9	Discontinuance Notice for Unauthorized Use of Service
Original Sheet No. 10	Discontinuance Notice of Service Due to an Irregularity
Original Sheet No. 11	Balanced Billing Plan Application/Removal Form
Original Sheet No. 12	Third Party Notice
Original Sheet No. 13	Deferred Installment Agreement Form

1st Revised Sheet No. 14	Agreement by Property Owner or Agent to Pay Utility Bills During Periods When Property is Unoccupied
Original Sheet No. 15	Forms Advising Property Owner Tenant is Vacating Premises and Service has been Connected in Property Owner's Name Per an Agreement
Original Sheet No. 16	Guarantee of Payment for Natural Gas and/or Electric Service by a Second Party in Lieu of a Deposit
1st Revised Sheet No. 17	Deposit Warning Letter
Original Sheet No. 18	Deposit Request
Original Sheet No. 19	Final Bill Follow Up Letter Number 1
Original Sheet No. 20	Final Bill Follow Up Letter Number 2
Original Sheet No. 21	Customer Authorization to Release Information Relating to the Volume and/or Cost of Gas Furnished by Montana-Dakota Utilities Co.
Original Sheet No. 23	Request for Firm Natural Gas Sales Service
Original Sheet No. 24	Gas Transportation Agreement
1st Revised Sheet No. 26	Customers Agreement for Gas Extension
Substitute Original Sheet No. 28	Request for Natural Gas Service and Easement

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 rate schedules described in the preceding paragraph and has denoted as Volume No. 2.

Section 1

Original Sheet No. 1	Table of Contents

Section 2

Original Sheet No. 1	Preliminary Statement

Section 3

Original Sheet No. 1	Rate Summary Sheet
Original Sheet No. 2	Residential Gas Service Rate 60
Original Sheet No. 5	Ellsworth Air Force Base Rate 64
Original Sheet No. 7	East River Natural Gas System General Services Rate 66
Original Sheet No. 11	Firm General Gas Service Rate 70
Original Sheet No. 12	Small Interruptible General Gas Service Rate 71
Original Sheet No. 13	Optional Seasonal General Gas Service Rate 72
Original Sheet No. 22	Transportation Service Rates 81 and 82
Original Sheet No. 26	Large Interruptible General Gas Service Rate 85
Original Sheet No. 29	Purchased Gas Cost Adjustment Rate 88
Original Sheet No. 30	East River Natural Gas System Purchased Gas Cost Adjustment Rate 89

Section 4

Original Sheet No. 1	List of Gas Contracts with Deviation

Section 5

Original Sheet No. 1	General Provisions Rate 100
Original Sheet No. 3	Residential Rate for Regular Employees Rate 102
Original Sheet No. 19	Interruptible Gas Service Extension Policy Rate 119
Original Sheet No. 20	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	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 No. 4	Standard Customer Bill Form
Original Sheet No. 5	Disconnect Notice

Original Sheet No. 6	Application for Interruptible Natural Gas Service
Original Sheet No. 7	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 in Unoccupied
Original Sheet No. 12	Form 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 No. 17	Interruptible General Gas Service Agreement
Original Sheet No. 18	Request for Firm Natural Gas Sales Service
Original Sheet No. 19	Gas Transportation Agreement
Original Sheet No. 20	Customers Agreement for Gas Extension
Original Sheet No. 21	Gas Service Order
Original Sheet No. 22	Facilities Relocation Agreement
Original Sheet No. 23	Warning Notice
Original Sheet No. 24	Temporary Construction Heat Agreement

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 $2,173,380 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 27th day of December 2002.

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

By: Donald R. Ball
Donald R. Ball
Director of Regulatory Affairs

STATE OF NORTH DAKOTA)
:ss
COUNTY OF BURLEIGH)

Donald R. Ball, being first duly sworn, deposes and says that he is the Director of 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 27th day of December 2002.

Donald R. Ball
Director of Regulatory Affairs

Subscribed and sworn to before me this 27th day of December 2002.

STEVE REED
Notary Public
State of North Dakota
My Commission Expires Feb. 16, 2006

Steve Reed, Notary Public
Burleigh County, North Dakota
My Commission Expires: 2/16/06

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
Senior Attorney & Assistant Secretary
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506

TABLE OF CONTENTS

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Rate 66	East River Natural Gas System General Services	7	T
	Reserved for Future Use	8-10	
Rate 70	Firm General Gas Service	11	N
Rate 71	Small Interruptible General Gas Service	12	
Rate 72	Optional Seasonal General Gas Service	13	N
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Rate 85	Large Interruptible General Gas Service	26	C
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Rate 88	Purchased Gas Cost Adjustment	29	
Rate 89	East River Natural Gas System Purchased Gas Cost Adjustment	30	T
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Rate 125	New Installation, Replacement, Relocation and Repair of Company-Owned Gas Service Lines	25	
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Designation	Title	Sheet No.
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	Service Bill Adjustment Form	4
	Standard Customer Bill Form	5
	Disconnect Notice	6
	Application for Interruptible Natural Gas Service	7
	Customer Information Booklet	8
	Discontinuance Notice for Unauthorized Use of Service	9
	Discontinuance Notice of Service Due to an Irregularity	10
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	Third Party Notice	12
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	Agreement by Property Owner or Agent to Pay Utility Bills During Periods When Property is Unoccupied	14
	Form Advising Property Owner Tenant is Vacating Premises and Service Has Been Connected in Property Owner's Name Per an Agreement	15
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	Customers Agreement for Gas Extension	26
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	Request for Natural Gas Service and Easement	28

PRELIMINARY STATEMENT

*Designates Division 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. C

Bismarck Division

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

Rapid City Division

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

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.

(Continued)

(Continued)

PRELIMINARY STATEMENT

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.

RESIDENTIAL GAS SERVICE Rate 60

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

RATE:
Base Rate Per Month:
For customers with meters rated under 500 cubic feet per hour $ 7.00
For customers with meters rated over 500 cubic feet per hour $14.00

Commodity Charge:

First 10 dk per month	$5.096 per dk
Over 10 dk per month	$4.596 per dk I

MINIMUM BILL:
Base Rate.

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 PURCHASED GAS ADJUSTMENT:
Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 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.

ELLSWORTH AIR FORCE BASE Rate 64

AVAILABILITY:

Service under this rate schedule is available to the Ellsworth Air Force Base (EAFB).

RATE:

Base Rate Per Meter:	$95.00 per month
Interruptible Sales Commodity Charge:	$1.867 per dk

MINIMUM BILL:

Base Rate.

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 PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

GAS DELIVERY MAMAGEMENT FEE:

In addition to the Commodity Charge 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.

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

(Continued)

ELLSWORTH AIR FORCE BASE Rate 64

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 sales commodity charge rate set forth above, 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 $10.00 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.

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:
Base Rate 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

Non-Gas Commodity Charge*: All dk @ $1.761 per dk

* Gas Costs as defined in Rate 89 shall be added to the Non-Gas Commodity Charge.

MINIMUM BILL:
Base Rate.

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. T

COST OF PURCHASED GAS ADJUSTMENT:
Bills are subject to an adjustment for cost of purchased gas as provided in Rate 89 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.

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:

Base Rate Per Month:

For customers with meters rated under 500 cubic feet per hour $ 7.50
For customers with meters rated over 500 cubic feet per hour $15.00

Commodity Charge:

First 15 dk per month	$4.955 per dk
Over 15 dk per month	$4.456 per dk

I

MINIMUM BILL:

Base Rate.

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 PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 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.

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:

Base Rate	$40.00 per month	I
Commodity Charge:		
Maximum Rate per dk	$ 4.184 per dk	I
Minimum Rate per dk	$ 3.831 per dk	R

MINIMUM BILL:

Base Rate.

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. T

COST OF PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

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. T

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(Continued)

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

GENERAL TERMS AND CONDITIONS: (Cont.)

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 tail block of the applicable General Gas Service Rate 70 commodity charge rate, 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 $10.00 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.

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.

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:

Base Rate Per Month:

For customers with meters rated under 500 cubic feet per hour $ 7.50
For customers with meters rated over 500 cubic feet per hour $15.00

Commodity Charge:

	Winter	Summer	
First 15 dk per month	$5.104 per dk	$3.975 per dk	I
Over 15 dk per month	$4.605 per dk	$3.476 per dk	I

Winter - Effective for bills rendered October 1 through May 31
Summer - Effective for bills rendered June 1 through September 30

MINIMUM BILL:

Base Rate.

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 PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

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.

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

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 or Firm Gas Transportation Service Rate 84, whichever is applicable. T

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 or Firm Gas Transportation Service Rate 84, whichever is applicable. T

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(Continued)

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

AVAILABILITY: (Cont.)

Firm Gas Transportation Service Rate 84:

Firm transportation service is available for the firm requirements of those customers 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 or Large Interruptible General Gas Service Rate 85. Such firm requirements, subject to approval by the Company, must be set forth in a firm service agreement. T

RATE:

Base Rate:

Rate 81	$ 40.00	per month 1/	I
Rate 82	$150.00	per month 2/	
Rate 84	$ 40.00	per month if taken in conjunction with Small Interruptible General Gas Service Rate 71 3/	I
Rate 84	$150.00	per month if taken in conjunction with Large Interruptible General Gas Service Rate 85 3/	

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.

3/ In the event customer takes service through one meter under Rates 71 and 84 or Rates 85 and 84, the base rate under Rate 84 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.)

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(Continued)

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

RATE: (Cont.)

	Rate 81	Rate 82	Rate 84	
Maximum Rate per dk	$0.484	$0.177	$1.076	I
Minimum Rate per dk	$0.131	$0.090	$1.076	I
Nomination Charge per Month	$50.00	$50.00	$50.00	
Balancing Charge per dk	$0.342	$0.342	$0.342	

Fuel Charge:
Applicable to all dk transported to customers located within the distribution system. Charge does not apply to transmission level customers. See supplemental 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:
   a. 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.

   b. If the Company determines that firm capacity exists, requests for firm gas transportation service shall be processed on a first come first serve basis. Requests for interruptible transportation service shall be considered in accordance with the provisions of Rate 100, §V.10.

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TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

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 or Rate 84, whichever is applicable. 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. T

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 tail block commodity charge rate, 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 $10.00 per dk of gas used in excess of the volume of T

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TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

5. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - (Cont.)
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 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 due to shipper or pipeline constraints and the customer continues to take gas, the rate charged to the customer shall be the tail block of the Firm General Gas Service Rate 70 commodity charge rate plus any applicable penalties or charges set forth in Paragraph 6.a. The Company is under no obligation to notify customer of non-delivered volumes. T

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.

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TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

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.17. T

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 tail block commodity charge rate. 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. T

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TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

9. BALANCING: (Cont.)

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 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. T

(Continued)

(Continued)

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

9. BALANCING: (Cont.)

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 - Electronic measurement 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 a telephone tie to customer's telephone system accessible 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 electronic

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TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

11. METERING REQUIREMENTS - (Cont.)
measurement 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 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. C

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

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.

d. At no time shall Company have the responsibility to deliver gas in excess of customer's nomination.

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

(Continued)

TRANSPORTATION SERVICE
(Rates 81, 82, 84)

GENERAL TERMS AND CONDITIONS: (Cont.)

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. T

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.

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.

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. T

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

RATE:

Base Rate:	$150.00 per month
Commodity Charge:	
Maximum Rate per dk	$2.261 per dk R
Minimum Rate per dk	$2.174 per dk

MINIMUM BILL:

Base Rate.

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. T

COST OF PURCHASED GAS ADJUSTMENT:

Bills are subject to an adjustment for cost of purchased gas as provided in Rate 88 or any amendments or alterations thereto.

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(Continued)

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

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. T

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 tail block commodity charge rate, 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 $10.00 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. T

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.

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.

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 an adjustment to reflect changes in its average cost of gas supply only when the amount of such adjustment 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 general rate case. 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.

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PURCHASED GAS COST ADJUSTMENT Rate 88

3. PURCHASED GAS COST ADJUSTMENT: (Cont.)

(b) (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. (C)

(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. (M)

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. (M)

(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). (M)

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

(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. (N)

(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. (M)

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PURCHASED GAS COST ADJUSTMENT Rate 88

3. PURCHASED GAS COST ADJUSTMENT: (Cont.)

(c) (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. (M)

(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. (M)

4. SURCHARGE ADJUSTMENT:

(a) 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. (T)

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 one-tenth of one 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). (T)

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PURCHASED GAS COST ADJUSTMENT Rate 88

5. UNRECOVERED PURCHASED GAS COST ACCOUNT: (Cont.)

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

(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: (T)

(i) Montana-Dakota shall first determine each month the unit cost for that month's natural gas supply as adjusted to levelize demand charges. (T)

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 (the cost of gas supply approved in the most recent rate case plus the Purchased Gas Cost Adjustment as calculated in Subsection 3(a)). (T) (T)

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PURCHASED GAS COST ADJUSTMENT Rate 88

5. UNRECOVERED PURCHASED GAS COST ACCOUNT: (Cont.)

(b) (1) (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. (T) (T)

(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: (T)

(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 (T (T

(Continued)

(Continued)

PURCHASED GAS COST ADJUSTMENT Rate 88

5. UNRECOVERED PURCHASED GAS COST ACCOUNT: (Cont.)

(c) (1) rate schedule excluding Rate 66. The account shall be increased in the event the adjustment is a negative amount. (T

(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). (T

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. (C

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

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 an adjustment to reflect changes in its average cost of gas supply only when the amount of such adjustment 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 established in initial rates or as approved in its most recent general rate case. 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.

(Continued)

(Continued)

EAST RIVER NATURAL GAS SYSTEM
PURCHASED GAS COST ADJUSTMENT Rate 89

3. PURCHASED GAS COST ADJUSTMENT: (Cont.)

(b) (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. N | N

(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 states. 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.

(Continued)

EAST RIVER NATURAL GAS SYSTEM
PURCHASED GAS COST ADJUSTMENT Rate 89

3. PURCHASED GAS COST ADJUSTMENT: (Cont.)

(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. T

4. SURCHARGE ADJUSTMENT:

(a) 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 one-tenth of one 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. T

(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: T

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EAST RIVER NATURAL GAS SYSTEM
PURCHASED GAS COST ADJUSTMENT Rate 89

5. UNRECOVERED PURCHASED GAS COST ACCOUNT: (Cont.)

(b) (1) (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: T

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 (the cost of gas supply approved in the most recent rate case plus the Purchased Gas Cost Adjustment as calculated in Subsection 3(a)). T T

(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.

(Continued)

(Continued)

EAST RIVER NATURAL GAS SYSTEM
PURCHASED GAS COST ADJUSTMENT Rate 89

5. UNRECOVERED PURCHASED GAS COST ACCOUNT: (Cont.)

(b) (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: T

(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. T

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EAST RIVER NATURAL GAS SYSTEM
PURCHASED GAS COST ADJUSTMENT Rate 89

5. UNRECOVERED PURCHASED GAS COST ACCOUNT: (Cont.)

(c) (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). T

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. T

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
Ipswich Public School	Firm Commercial	07-15-96 To 07-14-01	Rate 66	Rate/ Minimum Bill
Merillat Corporation	Firm Commercial	05-01-98 To 10-31-03	Rate 70	Rate

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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:

APPLICANT - A customer requesting Company to provide service.

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

COMPANY - Montana-Dakota Utilities Co.

NORMAL BUSINESS HOURS - 8:00 AM to 5:00 PM Monday through Friday excluding holidays.

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.

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.

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GENERAL PROVISIONS Rate 100

II. DEFINITIONS: (Cont.)

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. C

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.

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GENERAL PROVISIONS Rate 100

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. T

   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.

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(Continued)

GENERAL PROVISIONS Rate 100

III. CUSTOMER OBLIGATIONS: (Cont.)

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. 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.

7. 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. T

8. 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. L

IV. LIABILITY: T

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.

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GENERAL PROVISIONS Rate 100

IV. LIABILITY: (Cont.)

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. L

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. L

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,

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GENERAL PROVISIONS Rate 100

IV. LIABILITY: (Cont.)

5. FORCE MAJEURE - (Cont.)
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.

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.

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GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

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. T L

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.

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GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

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. Contact your local Montana-Dakota Utilities Co. office for this information. T

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. T L
   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.

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GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

6. CONSUMER DEPOSITS (Cont.)

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. T
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. T

7. METERING AND MEASUREMENT: L

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 electronic measurement 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: L

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GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

8. MEASUREMENT UNIT FOR BILLING PURPOSES: (Cont.)

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. Supercompressibility factor adjustments will be waived on monthly billed volumes of 250 dk or less. L

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY - Priority of Service from Highest to Lowest: L

a. Priority 1 - Firm sales and firm transportation services.

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.

(Continued)

(Continued)

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY: (Cont.)

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. T L

12. RETURNED CHECK CHARGE - A charge of $10.00 will be collected by the Company for each check charged back to the Company by a bank. L T

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.

(Continued)

(Continued)

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

13. TAX CLAUSE (Cont.) T

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: L

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, combustion gas 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. Disconnecting of gas appliances permanently removed from service or in connection with cut-outs.

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

4. Initial burner adjustment on residential gas burning appliances.

5. High bills or inadequate service complaints.

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

(Continued)

(Continued)

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

14. UTILITY CUSTOMER SERVICES: (Cont.)

7. Pilot relighting, testing thermocouple for proper operation and any pilot cleaning that can be done without removing pilot assembly.

8. Service calls for routine cut-ins, when the order is received prior to 3:30 p.m. on a regular work day will be considered as non-chargeable regardless if work is performed outside of normal working hours. T

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

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. L

17. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS - A fee of $18.00 will be collected for reconnecting gas sales or transportation service, during normal business hours, to any customer who has discontinued the same service at the same location during the preceding 12 month period. Standard overtime rates will apply after normal business hours. T

(Continued)

(Continued)

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

17. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS: (Cont.) 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 required electronic measurement equipment is necessary.

18. 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 $12.00 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. T L

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

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.

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(Continued)

GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

19. DISCONNECTION OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS: (Cont.) N

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 $12.00 before restoring gas service which has been disconnected for the above causes. N

20. 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: T

Meter Rating	Deposit Amount
Residential	
All	$10.00
Non-Residential	
425 CFH* or less	$10.00
426 CFH to 1000 CFH	$20.00
Over 1000 CFH	$60.00

* 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.

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GENERAL PROVISIONS Rate 100

V. GENERAL TERMS AND CONDITIONS: (Cont.)

21. 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 125 - New Installation, Replacement, Relocation and Repair of Company-owned Service Lines
Rate 134 - Rules and Policies for Implementing Master Metering Restrictions

RATE FOR RESIDENTIAL GAS SERVICE FOR REGULAR EMPLOYEES T
OF MONTANA-DAKOTA UTILITIES CO., MDU RESOURCES GROUP, INC.
AND WHOLLY-OWNED SUBSIDIARIES OF MDU RESOURCES GROUP, INC. 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. T

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 stub(s), regulators, meters (excluding electronic measurement 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. T

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. Electronic measurement equipment costs shall be subject to the terms and conditions specified in Transportation Service Rates 81, 82, 84.

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INTERRUPTIBLE GAS SERVICE EXTENSION POLICY Rate 119

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.

b. Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (AI/PI), 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.

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=

$$\frac{\text{Annual Customer Charge + (Project Estimated 3rd Year Annual Dk x Unit Margin)}}{\text{Levelized Annual Revenue Requirement Factor}}$$

4. Cost of the extension shall include, if applicable, the gas main extension(s), valves, tap setting and associated equipment, barricade, service stub(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 stub is that portion of the gas service extending from the main to the private property line or easement boundary.

   The service line is that portion of the gas service extending from the service stub to the connection at the house regulator and/or meter. Service lines are installed at customer's expense and are owned by and shall be maintained at customer's expense except for those customers served under General Services Rate 66.

   For those customers served under General Services Rate 66, the service line will be treated in accordance with Rate 125.

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.

FIRM GAS SERVICE EXTENSION POLICY Rate 120

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.

FIRM GAS SERVICE EXTENSION POLICY Rate 120

B. Customer Extensions (Cont.)

1. 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. 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 ¶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.

FIRM GAS SERVICE EXTENSION POLICY Rate 120

B. Customer Extensions (Cont.)

3. 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.

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. 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.

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

The following will apply, except for customers served on Rate 66, to all new customer-owned gas service lines, and to the replacement, relocation and repair of all gas service lines on private property. T

1. The customer shall be charged for a new service line on the basis of direct costs to the Company including material, labor, transportation, etc. Such costs shall include ordinary payroll and general overhead loadings. 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.

2. If the customer's service line requires replacement, was installed less than 25 years ago, and is coated steel or plastic pipe, such line shall be pressure tested in accordance with the Company's rules for pressure testing. If the service line is found to be leaking due to faulty installation or due to a lack of cathodic protection, has damaged coating, surface pitting, etc., the line will be repaired or replaced at no cost to the customer. T

3. For coated steel pipe service lines installed more than 25 years ago, which cannot be repaired and need replacement and for bare pipe service lines of any age, the customer shall be charged in accordance with Paragraph 1 above. T

   In accordance with Company standards, service line replacements will be constructed with outside risers and meters. Such reconstruction will nearly always involve minor changes in inside piping. The inside piping changes may be incorporated into the total footage to be billed as provided in Paragraph 1 above.

4. Where the customer's gas service line must be replaced because the mains are being relocated (alley to street or street to alley), such line change or relocation will be made at the Company's expense if the service line is coated steel or plastic pipe and was installed less than 25 years ago. If the line is older and passes the required pressure test, the replacement will be made at the Company's expense. If such older line does not pass the required pressure test, the line shall be replaced at the customer's expense except that the customer shall be charged only for the lesser of: (a) the equivalent length of the old service line or (b) the actual length of the new service line if it is shorter than the older service line being replaced. The basis for billing the customer shall be as outlined in Paragraph 1 above. T

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

5. Where service line location changes are made due to building encroachments (a building is being constructed or is already located over a service line, etc.), or due to the necessity to increase the size and capacity of an existing service line because of increased demand, the customer shall be charged on the basis of direct costs incurred by the Company, as outlined in Paragraph 1 above.

6. Whenever a service line is damaged by excavating and/or earth-moving equipment, etc., and is either repaired or replaced in whole or in substantial part, such work shall be charged for on a direct cost basis including ordinary payroll and general overhead loadings. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor. Damages done by the customer or someone working directly for him shall be paid for by the customer. Such charges shall be made regardless of the age of the damaged service line.

NEW INSTALLATION, REPLACEMENT, RELOCATION AND
REPAIR OF COMPANY-OWNED GAS SERVICE LINES Rate 125

The following will apply to all Company-owned gas service lines for service to those customers served under Rate 66.

1. New Service Lines
   a. The Company will install, at its expense, a service line extending up to 150 feet within the customer's property line. At such time as the primary distribution system is under construction, the customer shall be charged for the required service line exceeding 150 feet, on the basis of direct costs to the Company including material, labor, transportation, etc. Such costs shall include ordinary payroll and general overhead loadings. For service lines installed after completion of the primary distribution system, the customer will pay to the Company an amount equal to the excess footage multiplied by the average per foot installation cost. The average per foot installation cost will be determined annually based on the average state-wide system cost for service line installations.

   b. The Company will provide service to rural customers requiring a tap setting on South Dakota Intrastate Pipeline Company's transmission line, however a contribution may be required pursuant to the currently effective Firm Gas Service Extension Policy Rate 120. The rural customers' required service line will be treated in accordance with paragraph 1a above.

2. Where the customer's gas service line must be replaced because the mains are being relocated (alley to street or street to alley), such line change or relocation will be made at the Company's expense.

3. Where service line location changes are made due to building encroachments (a building is being constructed or is already located over a service line, etc.), or due to the necessity to increase the size and capacity of an existing service line because of increased demand, the customer shall be charged on the basis of direct costs incurred by the Company, including material, labor, transportation, etc. Such costs shall include ordinary payroll and general overhead loadings.

4. Whenever a service line is damaged by excavating and/or earth moving equipment, etc., and is either repaired or replaced in whole or in substantial part, such work shall be charged for on a direct cost basis including ordinary payroll and general overhead loadings. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor. Damages done by the customer or someone working directly for customer shall be paid for by the customer. Such charges shall be made regardless of the age of the damaged service line.

RULE 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 starts 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 starting 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.

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(Continued)

RULE 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.

(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.

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RULE AND POLICIES FOR IMPLEMENTING MASTER
METERING RESTRICTIONS Rate 134

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.

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RULE 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.

(T)

CONSUMER'S DEPOSIT RECEIPT

H

CONSUMER'S DEPOSIT RECEIPT

DEPOSIT NUMBER
812525509

DEPOSIT AMOUNT
$50.00

SERVICE ADDRESS
802 Sweetbriar
Rapid City SD57701

ACCOUNT NUMBER
13 598 556 12 661 0370 0

DATE
11/15/91

RECEIVED OF:
CAR-RT SORT ** CR32
John Doe
802 Sweetbriar
Rapid City SD 57702-5664

A DEPOSIT OF 50.00 DOLLARS 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. THIS STATEMENT SHALL CONSTITUTE A RECEIPT OF SAID DEPOSIT AND SHALL NOT BE TRANSFERABLE.

BY _____ MONTANA-DAKOTA UTILITIES CO.

POSITION _____ STREET ADDRESS _____

21019 (2-88) Revised 7-91

(T)

NEW CUSTOMER APPLICATION CARD - RESIDENTIAL SERVICE (T)

MONTANA-DAKOTA UTILITIES CO. front 20800(10-78) (Rev. 7/80)
CUSTOMER APPLICATION CARD — RESIDENTIAL SERVICE

Date Service to Begin: ___/___/___ _____ (Acct. No.)

Name (Print) _____ (Last) (First) (Middle Initial) _____ (Social Security No.)

Service Address: _____ (Number) (Street) (Apt. No.)

Mailing Address: *(If different)* _____

Home Phone: _____ Work Phone: _____

Present Place of Employment (Name): _____

Employer's Address: _____

Length of employment with present employer: Months _____ Years _____

Occupation: _____

Other Adult Occupant's Name: _____

Other Adult Occupant's Employer & Work Phone: _____

Any Dependents Living With You? Yes ___ No ___ Ages: _____

Is any member of your household 65 years *(Mont. 62)* of age or older? Yes ___ No ___

Is any member of your household on life support equipment? Yes ___ No ___

Name of nearest relative not living with you: _____

Relationship: _____ Telephone: _____

Address: _____

(Over)

back

Type of Dwelling: Apt. ☐ Duplex ☐ Mobile Home ☐ House ☐ Condo ☐ Townhouse ☐

If Renting, Landlord's Name: _____ City: _____

Landlord's Address: _____ Phone: _____

Your Previous Address: _____ (Street) (City) (State)

Customer of MDU Before? Yes ___ No ___ Where: (City) _____

When was that Service Discontinued? _____

Applicant whose signature appears below 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's pipes, wires, meters, or other equipment. Applicant agrees to pay for all services for which a bill is rendered.

Date: _____ Signature: _____

DO NOT WRITE BELOW — FOR OFFICE USE ONLY

Service: Gas ___ Electric ___

Identification: Current Driver's License—State _____
—Number _____

Deposit Required: Yes _____ No _____

Deposit Amount: _____ Date Paid: _____

Guarantor of Payment: _____ (Name) (Phone)

Third party be contacted before a disconnect? Yes ___ No ___

If Yes, list name and address of person, agency or complete applicable Third Party Notification Form: _____ (Name of Person or Agency) (Address)

Employee Signature: _____

Remarks: _____

(T)

Date Filed: August 10, 1990 Effective Date: September 20, 1990

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

NEW CUSTOMER APPLICATION CARD - GENERAL SERVICE

20902(6-81) (Rev.11/87) MONTANA-DAKOTA UTILITIES CO. front

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: ___/___/___

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

SD P.U.C. Section No. 6
2nd Rev. Sheet No. 3
Cancelling 1st Rev. Sheet No. 3

GAS METER ORDER (T)

20071 (2/68) (Rev. 6/88)

MONTANA-DAKOTA UTILITIES CO.

GAS METER ORDER No. G 691501

ORDER RECEIVED BY:	HOW RECEIVED	TIME	NAME OF PERSON PLACING ORDER	DATE	TOWN	ACCOUNT NO.
A	TELEPHONE ☐ IN PERSON ☐ LETTER ☐	A M.	A	A	A	A

CONNECT METER FOR	DISCONNECT METER FOR
A	A

TELEPHONE NO.	MAILING ADDRESS (AND IF DIFFERENT) SERVICE ADDRESS	CITY LIMITS
A	A	A IN or E OUT

CUSTOMER CLASS IN	RATE	SERVICE REQUESTED	PREVIOUS ADDRESS
S	A	GAS ONLY A GAS & ELECTRIC	A

DEPOSIT	NO DEPOSIT REQUIRED	FORWARDING ADDRESS
NO. A $	JOB OWNER A REFERENCES	A

METER IN

COMPANY NO.	MANUF.	SERIAL NUMBER	SIZE
S	S	S	S S

DATE	DIALS	STANDARD READING	GAUGE PRESSURE
S	S	S	LBS. S OZS.

METER LOCATION: OUTSIDE | BASEMENT | MAIN FLOOR S | UPSTAIRS | GARAGE S READ OUT

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

REGULATORS: 1ST S 2ND
ORIFICE SIZE S

ATMOS. PRES.	PRESSURE FACTOR	FACTORED METER
E	E	YES E NO

INSTRUMENT	CORRECTING TO CCF	CORRECTED READING
E	10 E 100 1000	S

DIALS	CORRECTING TO CCF	UNCORRECTED READING
E	10 E 100 1000	S

PILOT INSPECT S YES NO
INSULATOR INSPECT S YES NO
DISTRIBUTION ACCT. S YES NO
TRANSMISSION ACCT. S YES * NO
* COMPUTER LINE NO. E

WORK DONE BY: A E S

CONNECT MICI A | DISCONNECT MICI A TAM A

FORM KEY

A ACCOUNTING
E ENGINEERING
S SERVICEMAN

METER OUT

DATE	COMPANY NO.	SERIAL NO.
S	S	S

STANDARD READING	UNCORRECTED READING
$	B

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

* REASON METER REMOVED
☐ RANDOM TESTING A ☐ PERIODIC TESTING A ☐ NON REGISTER S
☐ DAMAGED C ☐ OTHER S

REMARKS:

*IF PRESSURE READING IS OTHER THAN STANDARD, GO TO NEXT RED SECTION.

(T)

Date Filed: December 7, 1990

Effective Date: Service on and after December 14, 1990

Issued By: C. Wayne Fox - Vice President

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc
400 North Fourth Street
Bismarck, ND 58501

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

SD P.U.C. Section No. 6
2nd Rev. Sheet No. 4
Cancelling 1st Rev. Sheet No. 4

CONSUMER BILLING ADJUSTMENT FORM (T)

21062(6-81)
(Rev. 9/87)

MONTANA-DAKOTA UTILITIES CO.
CONSUMER BILLING ADJUSTMENT

DIV _____ DIST _____

ACCOUNT NUMBER						DATE		
TOWN	CYCLE	BOOK	LOCATION	T	SQ	MO	DAY	YR
6					19	21		

NAME: _____ ADDRESS: _____

27 TC 65 OP 29 1

DR/CR	COMMODITY AMOUNT	DEMAND/KVAR AMOUNT	FUEL/PGA AMOUNT	DR/CR
30	31	40	49	56

ST. TAX AMOUNT	MUNI-TAX AMOUNT	RENTAL AMOUNT
57	64	71

27 TC 65 OP 29 2

COUNTY TAX AMOUNT	TOTAL ADJUSTMENT AMOUNT	CCF/KWH CONSUMP
30	37	46

ON PEAK CONS TOD	ACTUAL DEMAND	BILLING DEMAND
55	64	71

27 TC 65 OP 29 3

DISCOUNT AMOUNT	REAS CODE	HIST. PER.
30	39	41

THERMS	BILLING FACTOR	BASE RATE AMT.	UNBILLED DEM AMT.
43	50	56	61

Remarks: _____

Prepared By:	Approved By:	Date:

WHITE — Data Processing Dept. Copy YELLOW — Division Office Copy PINK — District Office Copy

(T)

Date Filed: December 7, 1990 Effective Date: Service on and after December 14, 1990

Issued By: C. Wayne Fox - Vice President
Regulatory Affairs & General Services

STANDARD CUSTOMER BILL FORM (T)

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 YOUR LOCAL MONTANA-DAKOTA UTILITIES CO. OFFICE WHERE YOU MAKE PAYMENT

H

PAYMENT AMOUNT

PAYMENT AMOUNT

DIRECT PAYMENTS TO
MONTANA-DAKOTA UTILITIES CO

PLEASE PAY THIS AMOUNT
$

FOR PROPER CREDIT PLEASE RETURN ENTIRE STUB (UPPER PORTION) WITH YOUR PAYMENT.

ACCOUNT NAME SERVICE ADDRESS		BILLING DATE DUE DATE

TYPE OF SERVICE	READING DATE	NO DAYS	METER READING PRESENT	PREVIOUS	DIFFERENCE KWH-MCF	BILLING FACTOR FOR MULTIPLIER	USAGE KWH-KW-DK	AMOUNT

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

(T)

MONTANA-DAKOTA UTILITIES CO.
Box 1060
Rapid City SD 57709

0000

ACCOUNT NUMBER		
556 09 540 1340 7		
METER NO.	LOC.	BILLING MONTH
131815	39	DECEMBER

DISCONNECT NOTICE

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

John Doe
802 Sweetbriar Rd.
Rapid City. SD 57701

AT 802 Sweetbriar Rd.
100010101210 17
---- 8 - - - ---

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 _____ to restore service during normal working hours plus a deposit or additional deposit of _____ will be required before service is restored.

Date _____ By _____
Credit & Collection Department

PAST DUE	CURRENT	ACCT. BALANCE
47.00	49.00	96,00

DIRECT INQUIRIES TO MDU, BOX 1060
PHONE 605 342-0160 RAPID CITY SD 57709 *REFER
UNRESOLVED COMPLAINTS TO: S.D. PUBLIC UTILITIES COMMISSION
CAPITOL BLDG, 500 E CAPITOL, PIERRE, SD 57501 1-800-332-1782

APPLICATION FOR INTERRUPTIBLE NATURAL GAS SERVICE (T)

204747-68)
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

(T)

Date Filed: August 10, 1990 Effective Date: September 20, 1990

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

CUSTOMER INFORMATION BOOKLET (T)

(T)

CUSTOMER INFORMATION BOOKLET

ADDITIONAL CUSTOMER INFORMATION FOR SOUTH DAKOTA CUSTOMERS

Montana-Dakota Utilities Co. 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 public utilities in the state.

MDU 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. In most cases, the problem will be solved with a visit or phone call to your nearest MDU office. Our employees are trained to help you.

MDU will make a full and prompt investigation of all written complaints received. Please address all written complaints to the manager at your nearest MDU office. The address of your local MDU office appears on your utility bill or it is listed in your local telephone directory.

DISPUTES

Whenever a customer advises MDU, before the disconnection of natural gas or electric service, that any part of the billing, charges or service is in dispute, MDU 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 MDU must notify the customer that the customer has the privilege 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
1-800-332-1782

CREDIT AND DEPOSIT POLICIES

MDU'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.

MDU will not require a deposit or guarantee from any new or present customers who have established good credit. MDU 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 any utility 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 MDU.

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 MDU's rules on file with the South Dakota Public Utilities Commission. These rules are available for your inspection for electric customers at the Mobridge MDU office and for natural gas customers at the Rapid City MDU office.
4. You have broken the terms of the contract for service with MDU or have failed to furnish those things necessary to obtain utility service.
5. You have failed to allow MDU 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 MDU's equipment or tampering with MDU'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 MDU 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 (20) 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. MDU 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 MDU 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 MDU's business offices are not open to the public.

The customer can pay a delinquent bill at the last minute to avoid disconnection. MDU'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, MDU 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. MDU 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. MDU shall not disconnect residential utility service from Nov. 1 to March 31 without adding an additional 30 days to the normal disconnection date. MDU 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, MDU 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

MDU 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 MDU in an attempt to force payment of that bill, except when that person, even though not personally liable to MDU, 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 MDU's customer rules. A complete listing of MDU customer rules and South Dakota Public Utilities Commission rules, regulations and rate schedules are available for your inspection at the Mobridge MDU office for electric customers and the Rapid City MDU office for natural gas customers. Your billing, payment and desposit records are also available to you for inspection. MDU will furnish additional information as you may reasonably request.

DISCONTINUANCE NOTICE FOR UNAUTHORIZED USE OF SERVICE (N)

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

(N)

Date Filed: August 10, 1990

Effective Date: September 20, 1990

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

DISCONTINUANCE NOTICE OF SERVICE DUE TO AN IRREGULARITY (N)

20610(11-81)
(Rev. 2/88)

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: _____

WHITE — Customer YELLOW — File

(N)

BALANCED BILLING PLAN APPLICATION/REMOVAL FORM (N)

20221(3-79)
(Rev 3-90)

MONTANA-DAKOTA UTILITIES CO. (Front)

BALANCED BILLING PLAN APPLICATION/REMOVAL FORM

TC 27 13	NAME: (PRINT)	RESIDENCE PHONE:
OP	SERVICE ADDRESS:	BUSINESS PHONE:
29	CITY: STATE:	ZIP CODE:
MAILING ADDRESS: (If Different from Service Address)		

ALT. PAY AMT.	CNTR.
30	39

PLEASE CHECK ONE OF THE FOLLOWING:

( ) **BALANCED BILLING PLAN REQUEST**
I have read the description and the provisions of the BALANCED BILLING PLAN on the reverse side of this form and hereby authorize Montana-Dakota Utilities Co. to place my natural gas and/or electric service account on the BALANCED BILLING PLAN and I hereby agree to comply with the provisions of the plan.

( ) **BALANCED BILLING PLAN REMOVAL**
I hereby request that my natural gas and/or electric service account with Montana-Dakota Utilities Co. be removed from the BALANCED BILLING PLAN.

Date: _____ Signature: _____

Comments: _____

FOR INTERNAL USE ONLY	
ACCOUNT NUMBER	
6	19 0 1

OP6 — BALANCED BILLING REQUEST
OP7 — BALANCED BILLING REMOVE

WHITE — District Office Copy	YELLOW — Data Processing Copy	PINK — Customer Copy

MONTANA-DAKOTA UTILITIES CO. (Back)

BALANCED BILLING PLAN

DESCRIPTION OF THE PLAN

The Balanced Billing Plan is basically a moving average based on the customer's total natural gas and/or electricity used in the last 12 months or an average based on the months of service if less than 12 months. The billed amount under this plan will be based upon the average consumption and will normally change every month. The average will be calculated by adding the consumption over the past 11 months plus the current month's consumption. The average consumption times the current rate plus a percentage of any amount still owed will be the current Balanced Billing Plan payment.

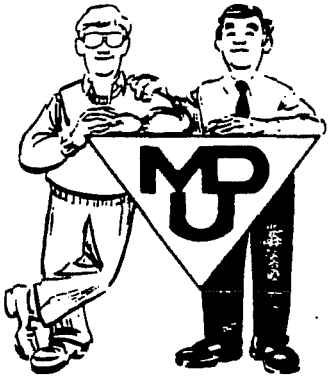
PROVISIONS OF THE PLAN

Once a customer is placed on the Balanced Billing Plan he may remain on the Plan provided the customer makes his Balanced Billing Plan payments by the delinquent date indicated on the customer's service bill.

Customers will be removed from the Balanced Billing Plan at their own request or automatically by the Company when the customer is 60 days in arrears. When a customer is removed from the Balanced Billing Plan at his request, the customer must make such request in writing by completing and signing a Balanced Billing Plan Removal Form (form no. 20221). Should a credit balance exist at this time it may be applied to the customer's current service bill or refunded at his request. A customer may be reinstated to the Plan upon request provided all amounts billed have been paid. (N)

THIRD PARTY NOTICE (N)

Would you benefit from a Third Party Notice?



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

Would you like to be a designated Third Party? *Montana-Dakota Utilities Co. (MDU) now 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 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.

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.

Request For Notice of Proposed Disconnection to Third Party

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, detach form, staple and seal, and mail to MDU as soon as possible.

20680(8-81)
South Dakota
Rev. 8/88)

(N)

20292(11-80)
(Rev. 4/87)

DEFERRED INSTALLMENT AGREEMENT FORM

(N)

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: _____ (N)

Date Filed: August 10, 1990 Effective Date: September 20, 1990

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

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

2089013-001
(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. T

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. T

_____, 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

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

20511(9-76)
(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

(N)

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

20458(6-81)
(Rev. 9/89)

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 (N)

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 $ _____. D

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

Thank you.

Sincerely,

_____
(MDU Representative)

20878(12-82)
(Rev. 11/92)
ND, SD & WY

DEPOSIT REQUEST (N)

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)

20877(12-82)
(Rev. 4/86)

(N)

FINAL BILL FOLLOW UP LETTER NUMBER 1 (N)

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

P. O. BOX 1060
RAPID CITY 57709

DATE
ACCOUNT
AMOUNT
SERVICE ADDRESS

OUR RECORDS INDICATE THAT YOUR ACCOUNT WITH MONTANA-DAKOTA UTILITIES CO. STILL REMAINS UNPAID. THE ACCOUNT HAS NOW BECOME PAST DUE AND WE REQUEST THAT YOU PROMPTLY PAY THIS ACCOUNT.

IF PAYMENT HAS RECENTLY BEEN MADE, PLEASE DISREGARD THIS NOTICE. THANK YOU FOR YOUR PAYMENT.

SINCERELY,

MONTANA-DAKOTA UTILITIES CO.

CREDIT AND COLLECTION DEPT.

(N)

FINAL BILL FOLLOW UP LETTER NUMBER 2 (N)

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

P. O. BOX 1060
RAPID CITY 57709

DATE
ACCOUNT
AMOUNT
SERVICE ADDRESS

OUR RECORDS INDICATE THAT YOUR ACCOUNT WITH MONTANA-DAKOTA UTILITIES CO. STILL REMAINS UNPAID IN SPITE OF OUR PREVIOUS REQUESTS FOR PAYMENT. IT IS OUR PRACTICE TO SUBMIT DELINQUENT ACCOUNTS TO A COLLECTION AGENCY FOR COLLECTION.

MONTANA-DAKOTA UTILITIES CO. AGAIN REQUESTS THAT YOU PROMPTLY PAY THIS OVERDUE ACCOUNT. IF YOUR REMITTANCE IS NOT RECEIVED BY MONTANA-DAKOTA UTILITIES CO. WITHIN TEN (10) DAYS OF THE DATE OF THIS NOTICE, YOUR ACCOUNT WILL BE SUBMITTED TO A COLLECTION AGENCY.

SINCERELY,

MONTANA-DAKOTA UTILITIES CO.

CREDIT AND COLLECTION DEPT.

(N)

CUSTOMER AUTHORIZATION TO RELEASE INFORMATION
RELATING TO THE VOLUME AND/OR COST OF GAS
FURNISHED BY MONTANA-DAKOTA UTILITIES CO. (N)

20022(12-85)

AUTHORIZATION

TO: Montana-Dakota Utilities Co.

I hereby authorize Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., to furnish to _____

_____

any information relating to the volume and/or cost of natural gas and/or electricity furnished by Montana-Dakota Utilities Co. for use at the following address: _____

_____

and account number: _____ .

This authorization shall remain in effect until _____ .

Dated this _____ day of _____ , 19 _____ .

_____
(Name—Printed)

_____
(Signature)

_____
(Street Address)

_____ _____
(Witness) (City) (State) (Zip)

(N)

REQUEST FOR FIRM NATURAL GAS SALES SERVICE (N)

M O N T A N A - D A K O T A U T I L I T I E S C O.

REQUEST FOR FIRM NATURAL GAS SALES SERVICE

I hereby certify that the estimated quantities listed below are representative of the daily firm natural gas requirement for

_____ located at

_____.

Volumes @ 14.73 psia

January	_____	Mcf/day
February	_____	Mcf/day
March	_____	Mcf/day
April	_____	Mcf/day
May	_____	Mcf/day
June	_____	Mcf/day
July	_____	Mcf/day
August	_____	Mcf/day
September	_____	Mcf/day
October	_____	Mcf/day
November	_____	Mcf/day
December	_____	Mcf/day

I hereby request that these quantities be provided to this location pursuant to an approved firm natural gas sales tariff. This daily volume will be considered first through the meter with the balance being transportation or interruptible retail gas.

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

CUSTOMER

_____
(Please print or type)

By _____

Agreed to and accepted by Montana-Dakota Utilities Co. this _____ day of _____, 19__.

_____
Don Hamann

Division Approval _____ (N)

GAS TRANSPORTATION AGREEMENT (N)

GAS TRANSPORTATION AGREEMENT

THIS AGREEMENT, made this _____ day of _____, 19____, is by and between MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., a Delaware corporation, hereinafter called "Company", and _____ _____ located in, _____ (City, State) hereinafter called "Customer".

Customer has entered into agreements to purchase natural gas and have that gas delivered to a "receipt point" using _____ as Shipper.

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.

In the event of termination of transportation services by Williston Basin Interstate Pipeline Company (WBI) prior to the above expiration date, this agreement shall terminate.

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:

Receipt Point	Delivery Point	Rate Schedule	Mcf Maximum Delivery Point Quantity Per Day

2.1 DAILY NOMINATIONS. Customer or Customer's Agent shall on a daily basis, before 10:00 a.m. Central Time (9:00 a.m. Mountain Time), place a phone call to 1-800-638-6799 and advise Company's gas nominations service of the volume (Mcf) Customer has requested to be delivered at each delivery point and under each rate schedule during the gas day commencing at 9:00 a.m. Central Time (8:00 a.m. Mountain Time) the following day. Customer's daily nomination shall be its best estimate of the expected utilization for the gas day. Prior to weekends and holidays, Customer will be required to nominate for the non-business days involved. Customer's Location ID Number is 872011.

Until such time as the electronic measurement equipment discussed in the tariff is in place at the delivery point, Customer agrees to read the gas meter at 9:00 a.m. Central Time (8:00 a.m. Mountain Time) each day that a nomination is made and provide the current meter reading(s) and the time reading(s) are taken. This

(Continued) (N)

(Continued)

GAS TRANSPORTATION AGREEMENT (N)

information will be provided to the Company's gas nomination service at the same time the daily nomination is made.

Customer will pay Company a nominating fee in accordance with tariffs on file with the appropriate state regulatory body.

2.2 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.

2.3 METERING AND MEASUREMENT. Company will meter the quantity 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 by more than two percent, in which case the quantity transported 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.

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.

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 Time (8:00 a.m. Mountain Time).

Interruption - A suspension of transportation or retail natural gas service deemed necessary by Company.

Nomination - The daily volume, in Mcf at 14.73 psia, 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 Time (8:00 a.m. Mountain 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 Williston Basin Interstate Pipeline Company (WBI) has entered into a Service Agreement for transportation service under the terms of WBI's FERC Gas Tariff, Original Volume No. 1-B.

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.

(Continued) (N)

(Continued)

GAS TRANSPORTATION AGREEMENT

(N)

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 REPLACEMENT OR SUPPLEMENTAL SALES SERVICE. Retail gas service or standby gas service may be available at this location during the time that this Agreement is in force. Customer may request that Company provide retail gas sales or standby service pursuant to Rate Schedule(s) _____ or _____. Service under such rates 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.

(N)

(Continued)

(Continued)

(N)

GAS TRANSPORTATION AGREEMENT

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: _____ Joseph R. Maichel, President
Title: _____	
Attest: _____ **	Attest: _____ Lester H. Loble, II, Secretary
Title: _____	

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

(N)

20133 (6-93)

Customers Agreement for Gas Extension

FIRM GAS SERVICE (RATE 120)
CUSTOMER EXTENSION

PRELIMINARY AGREEMENT

THIS AGREEMENT, made and entered into this _____ day of _____, 19 _____, 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 South Dakota; and

WHEREAS, such service will necessitate the construction by Company of a gas main extension, as shown on the map marked Exhibit "A" attached hereto; and the installation of the necessary facilities.

NOW, THEREFORE, in consideration of the mutual convenants 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, 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 $ _____, the receipt whereof is hereby acknowledged. It is further agreed that after facilities have been placed in service Company shall as part of the "Final Agreement" recalculate the Customer's cost participation as outlined below.

2. Interest will be paid by Company to Customer on any refunds made to Customer who has made a cash contribution for the project. 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.

3. "Project", as used in this Agreement, shall include, if applicable, the gas main extension(s), valves, tap setting and associated equipment, tap barricade, service stub(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.

4. 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.

5. 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.

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

_____ _____
Customer Division Manager

FINAL AGREEMENT

WHEREAS, the actual cost of construction differed from the estimated amount, an adjustment is required.

Final Actual Cost of Project ..... $ _____
Less Maximum Allowable Expenditure ..... $ _____
Final Cost Participation ..... $ _____
Preliminary Cost Participation ..... $ _____
Difference to be: ☐ Paid to Company
☐ Refunded to Customer .. $ _____

1. If, within the five-year period after 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 expenditure, in accordance with the Firm Gas Service Extension Policy Rate 120.

2. No refund shall be made by Company to Customer until the new applicants begin taking service from the Company. If after the aforementioned five-year period, the $ _____ 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.

Customer hereby acknowledges that all other portions of this Agreement as signed on _____ remain in full force and effect.

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

_____ _____
Customer Division Manager

REQUEST FOR NATURAL GAS SERVICE AND EASEMENT (N)

Montana-Dakota Utilities Co.
Request For Natural Gas Service & Easement

NAME: _____ ○ RESIDENTIAL ○ COMMERCIAL

SERVICE ADDRESS: _____ (Street, City, State, Zip Code) _____ (Subdivision)

ADDRESS: _____ (If different from service address - Street/Box, City, State, Zip Code)

TELEPHONE: _____ (Work Number) _____ (Home Number)

CONTACT NAME: _____ (Last Name, First Name, Middle Initial) _____ (Title)

Energy Requirements

	Equipment Type	Input (MBTU)	Fuel Type	Annual Consumption
Space Heating				
Water Heating				
Other				
Meter Size		Reg. Type		Orif. Size

Service Location

↓ Street Side ↓

COMMENTS:

_____
_____
_____
_____

OTHER UNDERGROUND FACILITIES:

Electric -E-E-E-E-E-
Telephone -T-T-T-T-T-
Cable TV -C-C-C-C-C-
Sprinkler -S-S-S-S-S-
Other _____

I understand Montana–Dakota Utilities Co. will provide Natural Gas service to _____, South Dakota and I hereby grant Montana–Dakota Utilities Co. a pipeline easement over and across my property for constructing a pipeline to provide natural gas service. I intend to convert the above facility to natural gas within one (1) year of its availability to my facility.

_____ (Customer Signature) _____ (Date) _____ (MDU Representative)

WHITE: G.O. Drafting Dept. YELLOW: Marketing PINK: Customer

(N)

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

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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

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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. 1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	PGA Items	Total Rate
Residential Rate 60	2	$0.42 per day	$0.890	$3.632	$4.522
Air Force Service Rate 64	5	$250.00 per month	$0.059	$2.518	$2.577
Firm General Service Rate 70	11				
Meters rated < 500 cubic feet		$0.90 per day			
Meters rated > 500 cubic feet		$1.80 per day	$0.634	$3.632	$4.266
Small Interruptible Sales Rate 71	12	$175.00 per month	Per Contract	$3.632	Per Contract
Optional Seasonal Gas Service Rate 72	13				
Meters rated < 500 cubic feet		$0.90 per day			
Meters rated > 500 cubic feet		$1.80 per day			
Winter Gas Usage			$0.634	$3.773	$4.407
Summer Gas Usage			$0.634	$2.508	$3.142
Transportation Service	22				
Small Interruptible Rate 81		$225.00 per month			
Maximum			$0.304		
Minimum			$0.131		
Fuel Charge				$0.048	
Large Interruptible Rate 82		$350.00 per month			
Maximum			$0.141		
Minimum			$0.090		
Fuel Charge				$0.034	
Large Interruptible Sales Rate 85	26	$300.00 per month	Per Contract	$2.549	Per Contract

Date Filed: December 30, 2002 **Effective Date:**

Issued By: Donald R. Ball
Director of 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

PRELIMINARY STATEMENT
*Designates Region Office T

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 T

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

Rapid City Region T

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

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.
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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:	$0.42 per day	C
Distribution Delivery Charge:	$0.890 per dk	
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate	C

Minimum Bill:

Basic Service Charge. T

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. T

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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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: C

Basic Service Charge:	$250.00 per month
Distribution Delivery Charge:	$0.059 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. T T

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

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: C

Basic Service Charge:	$250.00 per month
Distribution Delivery Charge:	$0.059 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. T T

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.

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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 $50.00 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. C C

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.

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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: T

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. T

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:**

Issued By: Donald R. Ball
Director of Regulatory Affairs

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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:		C
For customers with meters rated under 500 cubic feet per hour	$0.90 per day	
For customers with meters rated over 500 cubic feet per hour	$1.80 per day	
Distribution Delivery Charge:	$0.634 per dk	
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate	C

Minimum Bill:

Basic Service Charge. T

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: T

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. T

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.

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State of South Dakota
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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:	$175.00 per month	C
Distribution Delivery Charge:		
Maximum Rate	$0.304 per dk	
Minimum Rate	$0.131 per dk	
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate	C

Minimum Bill:

Basic Service Charge. T

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. T T

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 $50.00 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. T I C

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.

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. T

   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. T

   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. C C

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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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:		C
For customers with meters rated under 500 cubic feet per hour	$0.90 per day	
For customers with meters rated over 500 cubic feet per hour	$1.80 per day	
Distribution Delivery Charge:	$0.634 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	C

Minimum Bill:

Basic Service Charge. T

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: T

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. T

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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.

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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. D

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. D

Rate:

Basic Service Charge:

Rate 81	$225.00	per month 1/
Rate 82	$350.00	per month 2/

C

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	$0.304	$0.141
Minimum Rate per dk	$0.131	$0.090
Balancing Charge per dk	$0.300	$0.300

C

C

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. T

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. D

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. D

   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 T

or interrupt, or $50.00 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. C

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. T

   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. T T

   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.17.

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 T

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. T

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. T T T

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. T

    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. T T

    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. T T

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.

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.
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

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. N

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

Rate:

Basic Service Charge:	$300.00 per month	C
Distribution Delivery Charge:		
Maximum Rate	$0.141 per dk	
Minimum Rate	$0.090 per dk	
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate	C

Minimum Bill:

Basic Service Charge. T

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.

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. T T

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 T 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 $50.00 per dk of gas used in excess of the volume of gas to which C 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.

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. N

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. N

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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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. T

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. T

(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). T

(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.

PURCHASED GAS COST ADJUSTMENT Rate 88

(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. T

(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).

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
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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. T

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. T

(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). T

(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. T

(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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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	05-01-98 To 10-31-03	Rate 70	Rate

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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. T

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 there is a building encroachment(s), 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. N N

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.

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. T

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.

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. T

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 T

amended, supercompressiblity calculation. Supercompressibility factor adjustments will be waived on monthly billed volumes of 250 dk or less. T

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from Highest to Lowest:
    a. Priority 1 – Firm sales service. D
    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. C

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. T

        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. T

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. T

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. N

18. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS – A customer who requests reconnection of service, at a T

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. T C

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. T

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 $30.00 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. C

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.

21. 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. N

    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. N

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. N

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. N

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	$40.00
Non-Residential	
425 CFH* or less	$40.00
426 CFH to 1000 CFH	$40.00
Over 1000 CFH	$70.00

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* Cubic feet per hour

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

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

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.

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

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. T

   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.

INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

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. T

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

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. T

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. N

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.

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. T

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.

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

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. N

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 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. N

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 the customer shall be charged on the basis of direct costs incurred by the Company. T

5. Whenever a service line is damaged 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. T

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. N

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.

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.

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.

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

CONSUMER'S DEPOSIT RECEIPT

Account

Received of:

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

NEW CUSTOMER APPLICATION CARD – GENERAL SERVICE

NEW CUSTOMER APPLICATION CARD - GENERAL SERVICE

20902(6-81) (Rev.11/87) MONTANA-DAKOTA UTILITIES CO. front

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:**

Issued By: Donald R. Ball
Director of 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

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

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

☐ 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

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: _____

REMARKS:

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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

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:

H

DIRECT PAYMENTS TO
MONTANA-DAKOTA UTILITIES CO.

☐ 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 KWH-MCF	AMOUNT

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 INFORMATION

FORM NO. 20064 (11/70) REV. (10-01)

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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

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

20474(7-88)
(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

CUSTOMER INFORMATION BOOKLET

ADDITIONAL CUSTOMER INFORMATION FOR SOUTH DAKOTA CUSTOMERS

Montana-Dakota Utilities Co 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 public utilities in the state.

MDU 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. In most cases, the problem will be solved with a visit or phone call to your nearest MDU office. Our employees are trained to help you.

MDU will make a full and prompt investigation of all written complaints received. Please address all written complaints to the manager at your nearest MDU office. The address of your local MDU office appears on your utility bill or it is listed in your local telephone directory.

DISPUTES

Whenever a customer advises MDU, before the disconnection of natural gas or electric service, that any part of the billing, charges or service is in dispute, MDU 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 MDU must notify the customer that the customer has the privilege 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
1-800-332-1782

CREDIT AND DEPOSIT POLICIES

MDU'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.

MDU will not require a deposit or guarantee from any new or present customers who have established good credit. MDU 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 any utility 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, guarantee, 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 MDU.

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 (other 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 MDU's rules on file with the South Dakota Public Utilities Commission. These rules are available for your inspection for electric customers at the Mobridge MDU office and for natural gas customers at the Rapid City MDU office.
4. You have broken the terms of the contract for service with MDU or have failed to furnish those things necessary to obtain utility service.
5. You have failed to allow MDU employees access to company equipment located on your premises for meter reading, inspection, maintenance, replacement of equipment or to conduct investigations for hazardous conditions.
6. Unauthorized use of MDU's equipment or tampering with MDU'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 MDU 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 (20) 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. MDU 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 MDU 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 MDU's business offices are not open to the public.

The customer can pay a delinquent bill at the last minute to avoid disconnection. MDU'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, MDU 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. MDU 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. MDU shall not disconnect residential utility service from Nov. 1 to March 31 without adding an additional 30 days to the normal disconnection date. MDU 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 premises, MDU 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

MDU 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 MDU in an attempt to force payment of that bill, except when that person, even though not personally liable to MDU, 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 MDU's customer rules. A complete listing of MDU customer rules and South Dakota Public Utilities Commission rules, regulations and rate schedules are available for your inspection at the Mobridge MDU office for electric customers and the Rapid City MDU office for natural gas customers. Your billing, payment and deposit records are also available to you for inspection. MDU 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

CUSTOMER INFORMATION BOOKLET

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

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

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

DEFERRED INSTALLMENT AGREEMENT FORM

20292(11-90)
(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:**

Issued By: Donald R. Ball
Director of Regulatory Affairs

Docket No.:

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

[illegible]
(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

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

20511(9-76)
(Rev. 12/86)

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

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

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

204[illegible]
Rev. [illegible]

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:**

Issued By: Donald R. Ball
Director of Regulatory Affairs

Docket No.:

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)

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

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)

30877(12-82)
(Rev. 4/88)

Date Filed: December 30, 2002 **Effective Date:**

Issued By: Donald R. Ball
Director of Regulatory Affairs

Docket No.:

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

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], [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 dependant 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

REQUEST FOR FIRM NATURAL GAS SALES SERVICE

This document is an attachment to the Interruptible General Gas Service Agreement dated _____ between Montana-Dakota Utilities Co. and _____ covering natural gas service to its 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____.

By: _____
(Gas Supply Department)

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 [redacted] 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 $[redacted]. 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

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)

CUSTOMERS AGREEMENT FOR GAS EXTENSION

21417(12-01)
(Rev. 11/00)

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

21487(12-91)
(Rev. 11/99)

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

GAS SERVICE ORDER

GAS SERVICE ORDER (Form 26927 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 / BID
____ 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	(.28798)	$_____
____ Installation of Customer Owned Line (8340) (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 (.2882___) 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:_____

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

GAS SERVICE ORDER

GAS SERVICE ORDER (Form 30937 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.

DATE E.F. MAPPED & BY WHOM | DATE SRV. 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:

WELDER/PUSHER: | LENGTH OF TEST: | TESTED BY: | PRESSURE TESTED TO: PSIG

INTERNAL COND. OF PIPE IF REPIPED: N/A __WET __DRY __FAIR __POOR | EXTERNAL COND. OF PIPE IF BARE: __N/A __GOOD __FAIR __POOR | TYPE OF COATING: N/A __BW __XTRU __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.8380 ____ . ____ W Vintage ____
Retire ____ B ____ 30R.03PU.8376 ____ . ____ W Vintage ____

Other ____ B ____ 30 __ .03PU. ____ . ____ W
Other ____ B ____ 30 __ .03PU. ____ . ____ W

ITEM	SIZE	MAIN	STUB	SERV	ITEM	SIZE	MAIN	STUB	SERV
ANODE-MAG-					TEE-PL-BUTT-				
CAP-DR-					TEE-PL-BUTT-				
CAP-PL-BUTT-					TEE-PL-TAP-				
CAP-PL-BUTT-					TEE-PL-TAP-				
CAP-PL-SKT-					TEE-PL-SKT-				
CAP-PL-SKT-					TEE-PL-SKT-				
CAP-WLD-					TEE-PL-HVT-				
COATING-TC-20					TEE-ST-ELF-				
COUP-PL-					TEE-STPTRN-				
COUP-PL-					TEE-STP-				
COUP-PL-BUTT-					TEE-SVC-H17590-				
COUP-PL-BUTT-					TEE-TAS-MU-				
COUP-PL-ELF-					TEE-TS-MU-				
COUP-PL-ELF-					TEE-WLD-				
DI-SU-WI-SPL					TRNS-PK-				
ELL-PL-90-					VLV-SLW- -INS				
ELL-PL-90-SKT-									
ELL-PL-90-SKT-					ITEM	ITEM NO.	MAIN	STUB	SERV
ELL-PL-45-BUTT-					EXEMPT MATERIAL	3999999			
ELL-PL-45-BUTT-					EXEMPT MATERIAL	3999999			
ELL-PL-90-BUTT-					WI-LOC-GU914-HMWPE	2579007			
ELL-PL-90-BUTT-					SMALL FITTINGS	2999991			
ELL-WLD-45-									
ELL-WLD-90-									
ELL-WLD-90LR-									
EFV-PL-									
LSF-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					WASTE MATERIAL				
RIS-38V-									
SLV-PL-S									

Date Filed: December 30, 2002 **Effective Date:**

Issued By: Donald R. Ball
Director of Regulatory Affairs

Docket No.:

N

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: _____

N

N

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.
A Division of MDU Resources Group, Inc.

N

TEMPORARY CONSTRUCTION HEAT AGREEMENT

N

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, including any and all claims and liability arising out of any negligent acts of the Company.

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: _____

N

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

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Date Filed: **Effective Date:**

Issued By: Donald R. Ball
Director of 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

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

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.

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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:	$0.42 per day
Distribution Delivery Charge:	$0.890 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

~~Base Rate Per Month:~~
~~For customers with meters rated under 500 cubic feet per hour $ 7.00~~
~~For customers with meters rated over 500 cubic feet per hour $14.00~~

~~Commodity Charge:~~

~~First 10 dk per month~~	~~$5.096 per dk~~
~~Over 10 dk per month~~	~~$4.596 per dk~~

Minimum Bill:

Basic Service Charge.~~Base Rate.~~

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 ~~Purchased Gas Adjustment~~:

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

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RESIDENTIAL GAS SERVICE Rate 60

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.

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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~~Base Rate Per Meter~~:	$250.00 per month
~~Interruptible Sales:~~ ~~Commodity Charge:~~Distribution Delivery Charge:	$0.059 per dk
Cost of Gas:	Determined Monthly - See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.~~Base Rate.~~

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 ~~Purchased Gas Adjustment~~:

~~Bills are subject to an adjustment for~~ The cost of ~~purchased~~ gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment ~~provided in~~ 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 ~~Commodity~~ 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.

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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)~~sales commodity charge rate set forth above~~, 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 $~~10~~50.00 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.

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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:

~~Base 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

~~Non-Gas Commodity Charge*~~Distribution Delivery Charge: All dk @$1.761 per dk

~~* Gas Costs as defined in Rate 89 shall be added to the Non-Gas Commodity Charge.~~

Cost of Gas: Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.~~Base Rate.~~

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 ~~Purchased Gas Adjustment~~:

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

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EAST RIVER NATURAL GAS SYSTEM
GENERAL SERVICES Rate 66

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.

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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:

~~Base Rate Per Month:~~

~~For customers with meters rated under 500 cubic feet per hour $ 7.50~~

~~For customers with meters rated over 500 cubic feet per hour $15.00~~

~~Commodity Charge:~~

~~First 15 dk per month~~	~~$4.955 per dk~~
~~Over 15 dk per month~~	~~$4.456 per dk~~

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.90 per day
For customers with meters rated over 500 cubic feet per hour	$1.80 per day
Distribution Delivery Charge:	$0.634 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

~~Base Rate.~~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 ~~Purchased Gas Adjustment~~:

~~Bills are subject to an adjustment for~~ The cost of ~~purchased~~ gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment

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~~provided in~~ 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:

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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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:~~Base Rate~~	$~~40.00~~175.00 per month
Distribution Delivery ~~Commodity~~ Charge:	
Maximum Rate ~~per dk~~	$~~4.184~~0.304 per dk
Minimum Rate ~~per dk~~	$~~3.831~~0.131 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge~~Base Rate~~.

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 ~~Purchased Gas Adjustment~~:

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

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 ~~tail block of the applicable~~ Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas)~~commodity charge rate~~, 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 $~~10~~50.00 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.

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.

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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	$0.90 per day
For customers with meters rated over 500 cubic feet per hour	$1.80 per day
Distribution Delivery Charge:	$0.634 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

~~Base Rate Per Month:~~

~~For customers with meters rated under 500 cubic feet per hour $ 7.50~~
~~For customers with meters rated over 500 cubic feet per hour $15.00~~

~~Commodity Charge:~~

	~~Winter~~	~~Summer~~
~~First 15 dk per month~~	~~$5.104 per dk~~	~~$3.975 per dk~~
~~Over 15 dk per month~~	~~$4.605 per dk~~	~~$3.476 per dk~~

~~Winter – Effective for bills rendered October 1 through May 31~~
~~Summer – Effective for bills rendered June 1 through September 30~~

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OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Minimum Bill:

Basic Service Charge.~~Base Rate~~.

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: ~~**Cost of Purchased Gas Adjustment:**~~

The cost of gas includes all applicable cost of gas items as defined in ~~Bills are subject to an adjustment for cost of~~ Purchased Gas Cost Adjustment ~~as provided in~~ 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. 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.

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~~ or Firm Gas Transportation Service Rate 84, whichever is applicable~~.

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~~ or Firm Gas Transportation Service Rate 84, whichever is applicable~~.

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TRANSPORTATION SERVICE Rates 81 and 82

~~Firm Gas Transportation Service Rate 84:~~
~~Firm transportation service is available for the firm requirements of those customers 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 or Large Interruptible General Gas Service Rate 85. Such firm requirements, subject to approval by the Company, must be set forth in a firm service agreement.~~

Rate:

Basic Service Charge~~Base Rate~~:		
Rate 81	$225.00	per month 1/
Rate 82	$350.00	per month 2/
~~Rate 84~~	~~$ 40.00~~	~~per month if taken in conjunction with Small Interruptible General Gas Service Rate 71 3/~~
~~Rate 84~~	~~$150.00~~	~~per month if taken in conjunction with Large Interruptible General Gas Service Rate 85 3/~~

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.

~~3/ In the event customer takes service through one meter under Rates 71 and 84 or Rates 85 and 84, the base rate under Rate 84 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	~~Rate 84~~
Maximum Rate per dk	~~$0.484~~0.304	~~$0.177~~0.141	~~$1.076~~
Minimum Rate per dk	$0.131	$0.090	~~$1.076~~
~~Nomination Charge per Month~~	~~$50.00~~	~~$50.00~~	~~$50.00~~

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Balancing Charge per dk	$0.300~~342~~	$0.300~~342~~	~~$0.342~~

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 ~~supplemental~~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.

   b. ~~If the Company determines that firm capacity exists, requests for firm gas transportation service shall be processed on a first come first serve basis. Requests for interruptible transportation service shall be considered in accordance with the provisions of Rate 100, §V.10.~~

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~~or Rate 84, whichever is applicable~~. 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)~~tail block commodity charge rate~~, 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 $~~10~~50.00 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 ~~due to shipper or pipeline constraints~~ and the customer continues to take gas, ~~the rate charged to~~ the customer shall be subject to ~~the tail block of the Firm General Gas Service Rate 70 commodity charge rate plus~~ 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.17.

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)~~tail block commodity charge rate~~. 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 ~~Electronic measurement~~ 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 ~~a~~ acceptable telephone ~~tie to customer's telephone~~ service ~~system accessible~~ 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~~electronic measurement~~ 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.

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.
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

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:

~~Base Rate:~~Basic Service Charge: $~~150.00~~300.00 per month

~~Commodity~~ Distribution Delivery Charge:

Maximum Rate ~~per dk~~	$~~2.261~~0.141 per dk
Minimum Rate ~~per dk~~	$~~2.174~~0.090 per dk

Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

~~Base Rate.~~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
Director of 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

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Cost of ~~Purchased Gas Adjustment~~:

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

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 ~~tail block commodity charge rate~~(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 $~~10~~50.00 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.

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

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 ~~an adjustment~~a PGA to reflect changes in its average cost of gas supply only when the amount of change in such ~~adjustment~~ 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 ~~general rate case~~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 ~~one-tenth of one~~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 ~~(the cost of gas supply approved in the most recent rate case plus the Purchased Gas Cost Adjustment as calculated in Subsection 3(a)~~.

(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).

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.

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

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~~an adjustment~~ to reflect changes in its average cost of gas supply only when the amount of such change in PGA ~~adjustment~~ 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 ~~established in initial rates or as~~ approved in its most recent PGA~~general rate case~~. 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~~one-tenth of one~~ 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 ~~(the cost of gas supply approved in the most recent rate case plus the Purchased Gas Cost Adjustment as calculated in Subsection 3(a)~~.

(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.

Montana-Dakota Utilities Co.
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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
~~Ipswich Public School~~	~~Firm Commercial~~	~~07-15-96 To 07-14-01~~	~~Rate 66~~	~~Rate/ Minimum Bill~~
Merillat Corporation	Firm Commercial	05-01-98 To 10-31-03	Rate 70	Rate

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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

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GENERAL PROVISIONS Rate 100

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Docket No.:

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.

~~NORMAL BUSINESS HOURS – 8:00 AM to 5:00 PM Monday through Friday excluding holidays.~~

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 there is a building encroachment(s), 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.

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 ~~Contact your local~~ Montana-Dakota Utilities Co.'s offices ~~for this information~~.

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.

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 ~~electronic measurement~~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 ~~and firm transportation~~ services.
    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~~10.00~~ 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, ~~combustion gas~~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. Disconnecting of gas appliances permanently removed from service or in connection with cut-outs.~~

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

~~3. Initial burner adjustment on residential gas burning appliances.~~

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. Pilot relighting, testing thermocouple for proper operation and any pilot cleaning that can be done without removing pilot assembly.~~

5. Service calls for routine cut-ins, when the order is received prior to 12:00~~3:30~~ 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~~ and on Saturday, Sunday, or legal holidays~~, 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~~17~~. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS ~~– A fee of $18.00 will be collected for reconnecting gas sales or transportation service, during normal business hours, to any customer who has discontinued the same service at the same location during the preceding 12 month period. Standard overtime rates will apply after normal business hours.~~ 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 ~~required~~ remote data acquisition ~~electronic measurement~~ equipment is necessary.

19~~18~~. 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 $30.00~~12.00~~ 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~~19~~. 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 $~~12~~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 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~~21~~. 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~~40.00
Non-Residential	
425 CFH* or less	$~~10.00~~40.00
426 CFH to 1000 CFH	$~~20.00~~40.00
Over 1000 CFH	$~~60.00~~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.

23~~22~~. 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 125 - New Installation, Replacement, Relocation and Repair of Company-owned 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

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.

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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 ~~stub~~line(s), regulators, meters (excluding ~~electronic measurement~~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.

INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

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. ~~Electronic measurement~~Remote data acquisition equipment costs shall be subject to the terms and conditions specified in Transportation Service Rates 81 and~~,~~ 82~~, 84~~.

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

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~~Customer~~ Charge + (Project Estimated 3rd Year Annual Dk x Distribution Delivery Charge~~Unit Margin~~)/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 ~~stub~~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 stub is that portion of the gas service extending from the main to the private property line or easement boundary.~~

   The service line is that portion of the gas service extending from the main~~service stub~~ to the connection at the house regulator and/or meter. ~~Service lines are installed at customer's expense and are owned by and shall be maintained at customer's expense except for those customers served under General Services Rate 66.~~

   ~~For those customers served under General Services Rate 66, the service line will be treated in accordance with Rate 125.~~

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.

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. ~~Customer~~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.

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

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

~~The following will apply, except for customers served on Rate 66, to all new customer-owned gas service lines, and to the replacement, relocation and repair of all gas service lines on private property.~~

~~2. The customer shall be charged for a new service line on the basis of direct costs to the Company including material, labor, transportation, etc. Such costs shall include ordinary payroll and general overhead loadings. 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.~~

~~2. If the customer's service line requires replacement, was installed less than 25 years ago, and is coated steel or plastic pipe, such line shall be pressure tested in accordance with the Company's rules for pressure testing. If the service line is found to be leaking due to faulty installation or due to a lack of cathodic protection, has damaged coating, surface pitting, etc., the line will be repaired or replaced at no cost to the customer.~~

~~2. For coated steel pipe service lines installed more than 25 years ago, which cannot be repaired and need replacement and for bare pipe service lines of any age, the customer shall be charged in accordance with paragraph 1 above.~~

~~In accordance with Company standards, service line replacements will be constructed with outside risers and meters. Such reconstruction will nearly always involve minor changes in inside piping. The inside piping changes may be incorporated into the total footage to be billed as provided in paragraph 1 above.~~

~~4. Where the customer's gas service line must be replaced because the mains are being relocated (alley to street or street to alley), such line change or relocation will be made at the Company's expense if the service line is coated steel or plastic pipe and was installed less than 25 years ago. If the line is older and passes the required pressure test, the replacement will be made at the Company's expense. If such older line does not pass the required pressure test, the line shall be replaced at the customer's expense except that the customer shall be charged only for the lesser of: (a) the equivalent length of the old service line or (b) the actual length of the new service line if it is shorter than the~~

~~older service line being replaced. The basis for billing the customer shall be as outlined in paragraph 1 above.~~

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 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~~5~~. Where service line location changes are ~~made~~required due to building encroachments (a building is being constructed or is already located over a service line, etc.~~), or due to the necessity to increase the size and capacity of an existing service line because of increased demand,~~ the customer shall be charged on the basis of direct costs incurred by the Company~~,~~. ~~as outlined in paragraph 1 above.~~

5~~6~~. Whenever a service line is damaged ~~by excavating and/or earth-moving equipment, etc., and is~~ 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 ~~including ordinary payroll and general overhead loadings~~. If the damage was

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

caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor. ~~Damages done by the customer or someone working directly for him shall be paid for by the customer. Such charges shall be made regardless of the age of the damaged service line.~~

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

NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF COMPANY-OWNED GAS SERVICE LINES Rate 125

~~The following will apply to all Company-owned gas service lines for service to those customers served under Rate 66.~~

~~1. New Service Lines~~

~~a. The Company will install, at its expense, a service line extending up to 150 feet within the customer's property line. At such time as the primary distribution system is under construction, the customer shall be charged for the required service line exceeding 150 feet, on the basis of direct costs to the Company including material, labor, transportation, etc. Such costs shall include ordinary payroll and general overhead loadings. For service lines installed after completion of the primary distribution system, the customer will pay to the Company an amount equal to the excess footage multiplied by the average per foot installation cost. The average per foot installation cost will be determined annually based on the average state-wide system cost for service line installations.~~

~~c. The Company will provide service to rural customers requiring a tap setting on South Dakota Intrastate Pipeline Company's transmission line, however a contribution may be required pursuant to the currently effective Firm Gas Service Extension Policy Rate 120. The rural customers' required service line will be treated in accordance with paragraph 1a above.~~

~~c.~~

~~2. Where the customer's gas service line must be replaced because the mains are being relocated (alley to street or street to alley), such line change or relocation will be made at the Company's expense.~~

~~3. Where service line location changes are made due to building encroachments (a building is being constructed or is already located over a service line, etc.), or due to the necessity to increase the size and capacity of an existing service line because of increased demand, the customer shall be charged on the basis of direct costs incurred by the Company, including material, labor, transportation, etc. Such costs shall include ordinary payroll and general overhead loadings.~~

~~4. Whenever a service line is damaged by excavating and/or earth moving equipment, etc., and is either repaired or replaced in whole or in substantial part, such work shall be charged for on a direct cost basis including ordinary payroll and general~~

NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF COMPANY-OWNED GAS SERVICE LINES Rate 125

~~overhead loadings. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor. Damages done by the customer or someone working directly for customer shall be paid for by the customer. Such charges shall be made regardless of the age of the damaged service line.~~

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.

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.

(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.

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.

DOCKET NO. NG02-____

TESTIMONY AND EXHIBITS

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

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

Before the Public Utilities Commission of South Dakota

Docket No. NG02-___

Direct Testimony
of
C. Wayne Fox

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

2 A. Yes, my name is C. Wayne Fox. My business address is 400 North
3 Fourth Street, Bismarck, North Dakota 58501.

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

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

7 Q. What are your duties and responsibilities with Montana-Dakota?

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

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

12 A. In 1964, I received a Bachelor of Science degree in Electrical
13 Engineering from Chicago Technical College, Chicago, Illinois. I received
14 a Master of Arts degree in Business Administration from the University of
15 Illinois, Springfield, Illinois, in 1975. Upon graduating from college in
16 1964, I joined the Illinois Commerce Commission, the state body
17 regulating public utilities in Illinois, as an electrical engineer. Upon
18 termination of my employment with the Illinois Commerce Commission in

1 June 1980, I was serving as Manager of the Public Utilities Division. In
2 that capacity, my duties included testifying in formal cases before the
3 Commission, formulating and coordinating Commission policies on
4 technical and administrative matters, processing formal and informal
5 cases, and advising the Commission on matters related to the regulation
6 of public utilities operating in the state of Illinois.
7 In June 1980, I joined Montana-Dakota as Assistant Treasurer -
8 Regulatory Affairs, retaining that position until May 1982 when I was
9 elected Assistant Vice President - Regulatory Affairs. In May 1985, I was
10 promoted to Vice President - Regulatory Affairs. In May 1987, my duties
11 were broadened to include the Company's purchasing and general
12 services activities. At that time, my title was changed to Vice President -
13 Regulatory Affairs and General Services. I assumed my present position
14 in August 2000.
15 I also have been involved with the activities of the Electric Power
16 Research Institute, the Edison Electric Institute and the American Gas
17 Association.
18 Q. Have you testified before this Commission and other state regulatory
19 bodies?
20 A. Yes. I have previously sponsored testimony before this
21 Commission, the Montana Public Service Commission, the North Dakota
22 Public Service Commission, the Minnesota Public Utilities Commission
23 and the Wyoming Public Service Commission.

1 In addition, during my tenure with the Illinois Commerce
2 Commission, I testified in a number of cases before that Commission.
3 Q. What is the purpose of your testimony?
4 A. The purpose of my testimony is to provide an overview of our
5 South Dakota natural gas operations, explain our request for a gas rate
6 increase and discuss the policies and reasons underlying the major
7 aspects of the request. I will also identify the Company witnesses in this
8 proceeding. I should note at the outset that this requested increase is
9 applicable only to our Black Hills system customers. This request does
10 not affect natural gas customers served from our East River system.
11 Q. Would you provide a summary of Montana-Dakota's gas operations in the
12 Black Hills region of South Dakota?
13 A. The Black Hills natural gas distribution system serves
14 approximately 40,800 customers in 13 communities. The customer mix is
15 about 88% residential, 12% firm general service, with the Air Force, small
16 interruptible and large interruptible customers making up less than 0.2% of
17 the customers. The residential, firm commercial and small interruptible
18 customers use natural gas primarily for space and water heating. As
19 such, Montana-Dakota's system has a low load factor with peak gas
20 requirements occurring during the winter with summer loads being small
21 by comparison. The total annual gas used by our Black Hills system
22 customers is 7.6 Mmdk as projected for 2003 in this case. Montana-
23 Dakota's Black Hills gas service area is a single operating region with a

1 regional office located in Rapid City, a district office located in Spearfish
2 and District Representatives stationed in three other communities in the
3 area. As of December 1, 2002, the Company had 64 full and part-time
4 employees who live and work throughout our Black Hills gas service area.
5 Q. Mr. Fox, did you authorize the filing of the rate application in this
6 proceeding?
7 A. Yes, I did.
8 Q. Why has Montana-Dakota filed this application for a gas rate increase?
9 A. Montana-Dakota is requesting an increase in its general gas rates
10 at this time because the current cost of providing natural gas service to
11 our Black Hills system customers is not adequately reflected in the
12 currently authorized rates. It should be noted that this application does
13 not include any cost changes related to the cost of gas which is handled
14 through the Commission authorized Purchased Gas Cost Adjustment
15 tariff, Rate 88.
16 Q. Would you please explain the basic elements that make up the total costs
17 of providing gas service and which of those elements is subject to
18 regulation by this Commission?
19 A. Yes. The costs of providing natural gas service can be best broken
20 down into two major categories; first, the cost of gas delivered to the town
21 border station, where it leaves the interstate or intrastate pipeline and
22 enters our distribution system, and second, the cost of delivering the gas
23 from the town border station through our distribution system to the

1 individual customers. We call this portion distribution costs or non-gas
2 costs.
3 Natural gas purchased from a producer or supplier is a commodity
4 like wheat or corn and prices are not regulated. The charges for moving
5 the gas to our distribution system on the pipeline system are regulated by
6 the Federal Energy Regulatory Commission or other regulatory agencies.
7 These two elements, which we call "gas costs", are passed on to our
8 customers on a dollar-for-dollar basis as specified in the Purchased Gas
9 Cost Adjustment tariff, and there is no profit made by Montana-Dakota.
10 This portion currently comprises about 70% of a typical residential bill for
11 gas service.
12 The distribution cost portion of our rates is regulated by this
13 Commission and is the subject of this proceeding. This portion includes
14 operation and maintenance expenses, depreciation, taxes, and a
15 component for the opportunity to earn a return on the investment we have
16 in facilities to provide natural gas service. The distribution costs are
17 currently about 30% of a typical residential bill. The last time this portion
18 of the rates increased was in January 1995.
19 Q. What is the amount of the increase requested?
20 A. As will be fully explained by other Company witnesses, the
21 Company is requesting an increase of $2,173,380.
22 Q. How will the requested increase affect the various classes of customers?

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

Class	Change
Residential	5.8%
Firm General Service	8.4%
Air Force	0.0%
Small Interruptible	0.0%
Large Interruptible	0.0%
Overall	5.8%

10 Q. What are the primary reasons that Montana-Dakota needs an increase at
11 this time?
12 A. The primary reasons are increases in operating expenses
13 (operation and maintenance costs, depreciation and taxes other than
14 income) and an increase in the investment in facilities used to provide
15 natural gas service to our Black Hills system customers.
16 Q. When was the last gas general rate increase for Montana-Dakota?
17 A. Montana-Dakota's Black Hills system gas rates were last increased
18 in early 1995. The increase was $500,000 annually on December 7, 1994
19 plus another $254,000 on January 1, 1995 to cover the cost of FAS 106.
20 The changes were authorized in Docket No. NG94-012.
21 Q. Would you please explain how Montana-Dakota has been able to hold its
22 gas rates down since January 1, 1995?

1 A. From late 1994 through 2002 the consumer price index has risen
2 approximately 21%. In spite of this increase, we have been able to hold
3 the line on our gas rates by finding ways of operating our business more
4 efficiently and taking advantage of new technologies where it makes
5 economic sense to do so. For example, we have created a centralized
6 customer call center in Bismarck for all of our customers in the four state
7 area and we have installed computers in our servicemen's trucks allowing
8 them to receive orders electronically resulting in savings of at least one
9 hour per day. We continue to look for opportunities to reduce costs and
10 increase efficiencies, however, we now find ourselves in a position where,
11 despite our efforts, we must seek rate relief.
12 Q. What policy changes are proposed by the Company in this filing?
13 A. We are proposing a change in policy regarding service lines.
14 Montana-Dakota is proposing to own all service lines on a prospective
15 basis. Currently, the customers own the service lines in all communities
16 served. We are proposing that Montana-Dakota will own, and pay for,
17 subject to appropriate extension policy conditions, all new and
18 replacement service lines on a prospective basis. This change will align
19 the ownership of the service line with the responsibility for ongoing testing
20 and maintenance of the lines, which rests with Montana-Dakota, and will
21 avoid customer confusion and frustration in those instances when a
22 replacement is necessary.

1 Q. Is Montana-Dakota proposing changes in its rate structure in this
2 proceeding?
3 A. Yes, Montana-Dakota is proposing a change in rate structure in this
4 filing. The proposed rate structure, which is described in detail by other
5 witnesses in this proceeding, is intended to provide greater price
6 predictability for our customers, and revenue stability for the Company.
7 The current rate structure produces a revenue stream which is very
8 sensitive to temperature. When the winter heating season is warmer than
9 normal, Montana-Dakota collects less than its distribution cost of service.
10 When the winter heating season is colder than normal, Montana-Dakota
11 collects more than its distribution cost of service. I believe it is essential
12 that the rate structure proposed by the Company in this filing be approved
13 by the Commission so that both the Company and its customers receive
14 an additional measure of protection from what will otherwise be the
15 financial effect of temperature.
16 Q. Will you please identify the other witnesses who will testify on behalf of
17 Montana-Dakota in this proceeding?
18 A. Yes. In addition to myself, Mr. J. Stephen Gaske, President of
19 Zinder Companies, Inc., will testify regarding the appropriate cost of
20 common equity and overall cost of capital for Montana-Dakota's gas
21 operations. Mr. Craig A. Keller, Vice President, Controller and Chief
22 Accounting Officer for Montana-Dakota will testify regarding the capital
23 structure and overall debt and preferred equity costs. Ms. Rita A. Mulkern,

1 Regulatory Analysis Manager for Montana-Dakota, will testify regarding
2 the total revenue requirements necessary for Montana-Dakota's Black
3 Hills system gas operations. Mr. Richard A. Espeland, Vice President –
4 Human Resources for MDU Resources Group, Inc., will testify regarding
5 the Supplemental Income Security Plan. Mr. Russell A. Feingold,
6 Managing Director of Navigant Consulting, Inc., will testify regarding
7 certain rate design issues and a proposed Distribution Delivery
8 Stabilization Mechanism (a weather normalization mechanism) and Ms.
9 Tamie A. Aberle, Pricing and Tariff Manager for Montana-Dakota, will
10 testify on the specific rate design proposals.
11 Q. Mr. Fox, are the rates requested in this proceeding just and reasonable?
12 A. Yes. In my opinion, the proposed rates are just and reasonable
13 because they are reflective of the total costs being incurred by Montana-
14 Dakota in providing gas service to its customers. The proposed rates will
15 allow Montana-Dakota the opportunity to earn a just and reasonable return
16 on its Black Hills area South Dakota gas operations.
17 Q. Does this complete your direct testimony?
18 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 Edison Electric Institute Electric Rate Fundamentals course. In 1986 I accepted an appointment as

1 assistant professor at Trinity University in San Antonio, Texas, where I taught
2 courses in financial management, investments, corporate finance, and corporate
3 financial theory.
4 In 1988 I returned to H. Zinder & Associates as a consultant. I have
5 testified or filed testimony or affidavits before the Federal Energy Regulatory
6 Commission on more than twenty occasions. Topics covered in these
7 submissions have included rate of return, capital structure, cost allocation, rate
8 design, and market power. I also have filed testimony on the cost of capital and
9 capital structure issues for electric, gas distribution and oil and gas pipeline
10 operations before seven state regulatory bodies and the Comision Reguladora de
11 Energia de México ("CRE"). In addition, I have testified on rate design and
12 pricing issues before the Maine Public Utilities Commission, the Iowa Utilities
13 Board and the Postal Rate Commission, and on issues related to generating plant
14 economics before the Wisconsin Public Service Commission. I have conducted
15 many studies on issues related to regulated industries and have served as an
16 advisor to numerous clients on economic, competitive and financial matters. I
17 also have spoken and lectured before many professional groups including the
18 American Gas Association and the Edison Electric Institute Rate Fundamentals
19 courses. Finally, I am a member of the American Economic Association and its
20 Transportation and Public Utilities Group, the Financial Management
21 Association, and the AGA Rate Committee.
22

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 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	$145,100.0	44.674%	9.027%	4.033%
Preferred Stock	$16,250.0	5.003%	4.622%	0.231%
Common Equity	$163,446.7	50.323%	12.000%	6.039%
TOTAL	$324,796.7	100.00%		10.303%

As my testimony discusses, an overall allowed rate of return of 10.303 percent, with a 12.00 percent return on common equity, represents the cost of capital for Montana-Dakota.

1 Company Background

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

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

14 In 2001, Montana-Dakota and the much smaller Great Plains served a
15 total of 236,000 residential, commercial and industrial gas distribution customers.
16 As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's
17 natural gas distribution assets comprised 7.0 percent of MDU Resources' total
18 assets. In addition, the natural gas distribution utility revenues and operating
19 income accounted for 11.5 percent and 1.5 percent of MDU Resources' total,
20 respectively. South Dakota accounted for 19 percent of the natural gas
21 distribution utility operating revenues, while North Dakota (39 percent), Montana
22 (25 percent), Wyoming (6 percent) and Minnesota (11 percent) accounted for the
23 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

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

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

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

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

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

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

9 Cost of Debt

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

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

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

15 A. Montana-Dakota's annual cost of preferred stock is 4.622 percent, as
16 shown also in the Prepared Direct Testimony of Craig Keller.

17 Interest Rates and the Economy

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

19 A. Investors are often influenced by their perceptions of the economy and both
20 short- and long-term trends. Page 1 of Schedule 1 of Exhibit No.___(JSG-2) shows
21 various general economic statistics. The economy has had a record of persistent
22 growth during the past thirty years, with only temporary recessionary periods. Real

growth in the Gross Domestic Product ("GDP") has averaged 3.2 percent annually during the past 30 years, 3.1 percent for the past 20 years and 3.1 percent for the past ten years. After shrinking during the first three quarters of 2001, the economy has been growing slowly lately but there are mixed signals such as a decline in private sector payrolls, that another recession may be occurring. Utility stock prices in general have increased recently, but many utilities still have stock prices that are well below the levels achieved prior to September 11, 2001. During the past 18 months there has been an increase in the perceived risk of common equity investments and also an increase in the perceived risk of utility investments.

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 2.8 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 2.1 percent.

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 remained relatively stable during the past two years. The recent yields on A-rated public utility bonds have been approximately 7.0 percent and the yields on Baa-rated public utility bonds have been approximately 7.6 percent.

1 Discounted Cash Flow ("DCF") Method

2 **Q13. Please describe the DCF method of estimating the cost of common equity**
3 **capital.**

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

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

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

22 A. There can be many different versions of the basic DCF formula,
23 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.

1 Flotation Cost Adjustment

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

4 A. Yes. There are significant costs associated with issuing new common
5 equity capital and these costs must be considered in determining the cost of capital.
6 Schedule 3 of Exhibit No. ___(JSG-2) shows a representative sample of flotation
7 costs incurred with 34 new common stock issues by natural gas transmission and
8 distribution companies between 1992 and 2001. Flotation costs associated with
9 these new issues averaged 4.85 percent. This indicates that in order to be able to
10 issue new common stock on reasonable terms, without diluting the value of the
11 existing stockholders' investment, Montana-Dakota must have an expected return
12 that places a value on its equity that is approximately 4.75 percent above book value.
13 The cost of common equity capital is therefore the investor return requirement
14 multiplied by 1.0475.

15 One purpose of a flotation cost adjustment is to compensate common
16 equity investors for past flotation costs by recognizing that their real investment in
17 the company exceeds the equity portion of the rate base by the amount of past
18 flotation costs. For example, the proxy companies generally have incurred flotation
19 costs in the past and, thus, the cost of capital invested in these companies is the
20 investor return requirement plus an adjustment for flotation costs. A more important
21 purpose of a flotation cost adjustment is to establish a return that is sufficient to
22 enable a company to attract capital on reasonable terms. This fundamental
23 requirement of a fair rate of return is analogous to the well-understood basic

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.

DCF Study of Natural Gas Distribution Companies

Q16. 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. To get around this problem, I have used the Moody's Natural Gas Distribution Companies as a proxy group for purposes of estimating the cost of common equity for Montana-Dakota's South Dakota natural gas distribution operations.

1 **Q17. How did you calculate the dividend yields for the companies in your**
2 **comparison group?**
3 A. These calculations are shown on page 3 of Schedule 2 of Exhibit No.
4 __(JSG-2). For the price component of the calculation I used the average of the high
5 and low stock prices experienced by each company during the six month period
6 from June 2002 to November 2002. The dividend yields were calculated for each
7 company by dividing the indicated annual dividend by the average of the stock
8 prices for each company. These dividend yields can be multiplied by the quarterly
9 DCF model factor (1 + .625 g) to arrive at the dividend yield component of the DCF
10 model.

11 **Q18. Please describe the method you used in estimating the future growth rate that**
12 **investors expect from this group of companies?**
13 A. I developed three different DCF analyses of the proxy companies based on
14 three different growth rate estimation methods. There are many methods that
15 reasonably can be employed in formulating a growth rate estimate, but an analyst
16 must attempt to ensure that the end result is an estimate that fairly reflects the
17 forward-looking growth rate that investors expect.
18 In the first approach I calculated a DCF rate of return using a combination
19 of securities analysts' growth projections and the Value Line retention growth
20 forecasts to produce a Second-Stage Retention Growth analysis. As a second
21 approach, I conducted a Basic DCF analysis that relied solely on the analysts'
22 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

Q19. 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.

Q20. 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 5.6 percent.

Q21. 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

1 companies may experience extended periods of growth for other reasons, in the
2 long-run, growth in earnings and dividends per share depends in part on the amount
3 of earnings that are being retained and reinvested in a company. Thus, the primary
4 determinants of growth for the proxy companies will be (i) their ability to find and
5 develop profitable opportunities; (ii) their ability to generate profits that can be
6 reinvested in order to sustain growth; and, (iii) their willingness and inclination to
7 reinvest available profits. Expected future retention rates provide a general measure
8 of these determinants of expected growth, particularly items (ii) and (iii).

9 **Q22. How can a company's earnings retention rate affect its future growth?**

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

17 $$.80 \times 15\% = 12\%$$

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

21 $$.20 \times 15\% = 3\%$$

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

1 **Q23. How did you calculate the expected future retention rates of the proxy**
2 **companies?**
3 A. For most companies, Value Line publishes forecasts of data that can be
4 used to estimate the retention rates that its analysts expect individual companies to
5 have 3-5 years in the future. Since these retention rates are projected for several
6 years in the future they should be indicative of a normal expectation for a primary
7 underlying determinant of growth that would be sustainable indefinitely beyond the
8 period covered by analysts' forecasts. While companies may have either
9 accelerating or decelerating growth rates for extended periods of time, the retention
10 growth rates expected to be in effect 3-5 years in the future generally represent a
11 minimum "cruising speed" that companies can be expected to maintain indefinitely.
12 The derivation of Value Line's retention growth rate forecasts for each of the proxy
13 companies is shown on page 4 of Schedule 2 of Exhibit No.___(JSG-2). The
14 projected earnings per share and projected dividends per share can be used to
15 calculate the percentage of earnings per share that are being retained and reinvested
16 in the company. This earnings retention rate is multiplied times the projected return
17 on common equity to arrive at the projected retention growth rate. The average
18 retention growth rate for the proxy companies is 5.6 percent.

19 **Q24. How did you utilize the projected earnings retention rates in estimating**
20 **expected growth for the proxy companies?**
21 A. As shown on page 5 of Schedule 2 of Exhibit No.___(JSG -2), I calculated
22 a weighted average of the analysts' projected growth rates and the projected
23 retention growth rates to derive long-term growth rate estimates for each of the

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 5.6 percent and the median is 4.8 percent.

Q25. 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 10.2 percent and 14.7 percent.

The median for the group is 11.1 percent and the average for the group is 11.9 percent.

Basic DCF Analysis

Q26. 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.

Q27. 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 10.7 percent and an average cost of 11.9 percent.

1 Primary DCF Analysis

2 **Q28. Would you please describe your Primary DCF analysis?**

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

9 **Q29. In your opinion, what are the factors that will affect growth rates for the**
10 **proxy companies in the future?**

11 A. One important factor will be growth in the overall economy. Page 1 of
12 Schedule 1 of Exhibit No.___(JSG-2) shows that the United States Gross Domestic
13 Product has grown at an average annual rate of 7.6 percent during the past 30 years.
14 During the past decade U.S. GDP growth has averaged 5.5 percent. It is reasonable
15 to expect that long-term future growth in the economy generally will be comparable
16 to past growth rates. For example, DRI-WEFA forecasts that the U.S. GDP will
17 grow at a rate of approximately 5.9 percent over the long-term.

18 Another factor will be demand for natural gas. Natural gas usage has been
19 increasing in recent years and many analysts are expecting demand to increase
20 steadily during the next decade and beyond. For example, the Energy Information
21 Administration of the U.S. Department of Energy forecasts that gas consumption in
22 the United States will grow from its current level of approximately 23 Tcf per year
23 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 six companies in this comparison group to grow at a rate that is somewhere in the range of 5.25 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.

Q30. 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

1 market-based primary DCF analysis indicates that the cost of capital for the proxy
2 companies is approximately in the range of **11.5 percent** to **12.6 percent**.

3 Risk Premium Analyses

4 **Q31. Have you conducted additional analyses in determining the cost of capital to**
5 **Montana-Dakota?**

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

22 Investors' expectations for the future are influenced to a large extent by
23 their knowledge of past experience. Ibbotson Associates annually publishes

1 extensive data regarding the returns that have been earned on stocks, bonds and U.S.
2 Treasury bills since 1926. Historically, the annual returns on large company
3 common stocks have exceeded the yields on Long-Term U.S. Government Bonds by
4 an average of 700 basis points (7.0 percent). However, the returns on relatively
5 small company stocks in the size range of Montana-Dakota's natural gas distribution
6 operations have been 1,520 basis points (15.2 percent) above the yields on long-term
7 government bonds. As shown on page 1 of Schedule 2 of Exhibit No. ___ (JSG-2),
8 Montana-Dakota is a fraction of the size of any of the proxy companies. In recent
9 months, the yield on long-term U.S. Government bonds has been approximately 5.1
10 percent. Adding a 7.0 percent premium to a yield of 5.1 percent indicates that
11 investors in large company common stocks expect a return of at least 12.1 percent.
12 Adding the 15.2 percent premium for companies in Montana-Dakota's size range
13 suggests a required return of 20.3 percent.
14 Another risk premium approach is to examine the long-term premium of
15 large company common stock returns as compared with returns on corporate bonds.
16 This premium has averaged 660 basis points (6.6 percent) annually over a long
17 period of time in the past. When this premium is added to the 7.0 percent yield on
18 Moody's corporate bonds that has prevailed in recent months, the result is an
19 investor return requirement for large company stocks of 13.6 percent. However,
20 over the long term companies in Montana-Dakota's size range have had a premium
21 of 1,480 basis points (14.8 percent) over the average returns on long-term corporate
22 bonds. When added to the recent average corporate bond yields, this size-related
23 premium suggests an expected return of 21.8 percent.

1 Alternative Equity Investment Analysis

2 **Q32. Have you analyzed the returns available on common equity investments in**
3 **other industries?**

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

11 **Q33. What level of returns are potentially available to unregulated companies?**

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

1996	27.57%
1997	29.35
1998	28.28
1999	30.08
2000	31.75
5-year Average	**29.41%**

Q34. 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 29.4 percent during the past five years. Similarly, the average level of return experienced by the S&P 500 companies has been approximately 21.47 percent. As this comparison indicates, an allowed return of 12.00 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

Q35. 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.

Q36. 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.

Q37. 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 7.6 percent of the assets of the median proxy company. Similarly, Montana-Dakota's gas distribution operating revenues and operating income are only 17.1 percent and 2.6 percent of the level for the median proxy company. Thus, depending upon the measure of size, the typical proxy company is somewhere between approximately six and 38 times the size of Montana-Dakota's natural gas distribution operations.

With its small revenue base, Montana-Dakota is subject to slightly greater risk that a major employer or industry, such as a mining or manufacturing

1 operation, might experience a downturn that would significantly affect overall
2 employment and income in the areas served.
3 Ibbotson Associates has documented the significantly higher returns that
4 generally have been associated with small companies. On a practical level,
5 Montana-Dakota's relatively small natural gas distribution operations are heavily
6 dependent upon a relatively undiversified local economy. Factors that negatively
7 influence the local economy can reduce demand for Montana-Dakota's gas
8 distribution services and adversely impact investments in facilities used to provide
9 those services.
10 In addition, the threat of bypass is more significant for a smaller
11 company and the threat is especially great for a company such as Montana-Dakota
12 that is located near a gas production area. Montana-Dakota also faces direct
13 competition from propane and heating oil for new and existing load in its South
14 Dakota service territory. Another risk faced by Montana-Dakota is the fact that it
15 recovers a substantial portion of its fixed costs in the volumetric component of its
16 rates and it does not have a weather normalization adjustment mechanism. In
17 contrast, several of the proxy companies have rate designs that better reflect the
18 fixed cost nature of their operations. These companies have slightly less rate
19 design risk as a result. Montana-Dakota is requesting in this filing a rate design
20 that better reflects costs, but until such rate design is approved, Montana-Dakota's
21 South Dakota gas distribution operations face somewhat greater rate design risk
22 than the typical company in the natural gas distribution proxy group.

1 Considering only its smaller size, Montana-Dakota might require a return
2 that is more than 100 basis points higher than the return required for the typical
3 proxy company. However, Montana-Dakota also faces somewhat above-average
4 rate design risk. Taken together, these considerations indicate that Montana-
5 Dakota's South Dakota gas distribution operations face above-average business
6 risk.
7
8 **Q38. What are the regulatory risks faced by Montana-Dakota's South Dakota utility**
9 **operations?**
10 A. Regulatory risk is closely related to business risk and might be
11 considered just another aspect of business risk. To the extent that the market
12 demand for a natural gas distribution company's services is sufficiently strong
13 that the company could conceivably recover all of its costs, regulators may
14 nevertheless set the rates at a level that will not allow full cost recovery. In effect,
15 the binding constraint on utilities is often posed by regulation rather than by the
16 working of market forces. One purpose of regulation is to provide a substitute for
17 competition where markets are not workably competitive. As such, regulation
18 often attempts to replicate the type of cost discipline and risks that might typically
19 be found in highly competitive industries. Moreover, there is the perceived risk
20 that regulators may set allowed returns so low as to effectively undermine
21 investor confidence and jeopardize the ability of gas distribution utilities to
22 finance their operations. Thus, in some instances regulation may substitute for
23 competition and in other instances it may limit the potential returns available to

1 successful competitors. In either case, regulatory risk is an important
2 consideration for investors and has a significant effect on the cost of capital for all
3 firms in the natural gas distribution industry.
4 South Dakota has a reputation for fair and equitable regulation that is
5 recognized by an above-average investment rank by Value Line. Thus, in my
6 opinion, Montana-Dakota's South Dakota natural gas operations should be
7 considered to have below-average regulatory risk relative to the proxy companies.

8 **Q39. Would you please describe Montana-Dakota's relative financial risks?**

9 A. Financial risk exists to the extent a company incurs fixed obligations in
10 financing its operations. These fixed obligations increase the level of income
11 which must be generated before common stockholders receive any return and
12 serve to magnify the effects of business and regulatory risks. Fixed financial
13 obligations also increase the probability of bankruptcy by reducing the company's
14 financial flexibility and ability to respond to adverse circumstances. One possible
15 indicator of investors' perceptions of relative financial risk in this case might be
16 obtained from bond ratings. Because Montana-Dakota does not have its own
17 bonds outstanding, it is difficult to make direct comparisons between the ratings
18 of Montana-Dakota and the proxy group. However, page 2 of Schedule 2 of
19 Exhibit No. ___ (JSG-2) shows the bond ratings assigned by Moody's and
20 Standard & Poor's to each of the companies in the comparison group and to MDU
21 Resources bonds that are secured by the assets of Montana-Dakota Utilities. The
22 median bond ratings for companies in the proxy group are A+/A for Standard &
23 Poor's and A2 for Moody's. In comparison, MDU Resources bonds carry an A+

1 rating with Standard & Poor's and an A2 rating with Moody's. This suggests that
2 the perceived risk of MDU Resources' bonds is almost identical to that of the
3 typical company in the comparison group. Examination of the capital structure
4 data shown on page 9 of Exhibit No. ___ (JSG-2), Schedule 2 shows that half of
5 the proxy companies have common equity ratios greater than Montana-Dakota's
6 filed common equity ratio, 50.3 percent, and half have common equity ratios less
7 than Montana-Dakota's. This common equity ratio, combined with its bond
8 rating, suggests average financial risk for Montana-Dakota's South Dakota natural
9 gas distribution operations.

10 **Q40. Would you please describe Montana-Dakota's market risks?**

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

18 **Q41. How do the overall risks of the proxy companies compare with the risks**
19 **faced by Montana-Dakota's natural gas distribution operations?**

20 A. Montana-Dakota faces overall risks that are slightly above average relative
21 to those of the proxy companies. Montana-Dakota has above-average business risks
22 due primarily to its exceptionally small size relative to the proxy companies and its
23 exposure to competition and a relatively undiversified economy. Montana-Dakota

also has slightly greater rate design risk than the typical company in the proxy group. In addition, it has financial risks that are average relative to the proxy companies. These factors and the perception of an above-average regulatory climate in South Dakota lead me to conclude that the overall risks of Montana-Dakota's natural gas distribution operations are average relative to the risks of the proxy companies.

III. SUMMARY AND CONCLUSIONS

Q42. 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:

1

	Investor Requirement Median/Average	Cost of Capital Median/Average
DCF Analyses		
Natural gas distribution Proxies:		
- Second-Stage Retention Growth	10.6%/11.4%	11.1%/11.9%
- Basic DCF	10.2%/11.4%	10.7%/11.9%
- Primary DCF	11.5%	12.0%
Benchmark Analyses		
Risk Premium Return Based On:		
- U.S. Treasury Bonds		
v. Large Companies	12.1	
v. Small Companies	20.3	
- Corporate Bonds		
v. Large Companies	13.6	
v. Small Companies	21.8	
Alternative Investments		
- S&P 500	21.5	
- Value Line Industrials	29.4	

2

3 My second-stage retention growth analysis indicates a median cost of
4 common equity capital of 11.1 percent and an average cost of 11.9 percent.
5 Because projected retention growth is sustainable indefinitely and it is directly
6 related to the growth rate expectations for an individual company, it is a good
7 indicator of the minimum growth rate that a company can maintain in the very
8 long run. However, companies can achieve growth through means in addition to
9 retained earnings. Consequently, analysts' forecasts provide the best measure of
10 expected growth for the foreseeable future. At this time, the average of the
11 analysts' forecasts and the retention growth forecasts for the proxy companies are

1 identical. Combining these two measures provides a good estimate of the long-
2 term growth that investors can reasonably expect from these proxy companies.
3 The Basic DCF analysis, which relies solely on the analysts' forecasts, also
4 provides a good estimate of investors' growth rate expectations and required return
5 for the proxy companies. This DCF analysis indicates a median required rate of
6 return of 10.7 percent and an average rate of return of 11.9 percent.
7 My primary approach has been to analyze a variety of sources of
8 information, including investment analysts' forecasts, in order to estimate a
9 weighted average annual growth rate that investors reasonably can expect the natural
10 gas distribution comparison companies to achieve during a long period of time in the
11 future. This primary DCF analysis indicates that the cost of capital for natural gas
12 distribution companies with risks comparable to those of Montana-Dakota is in a
13 range between 11.5 percent and 12.6 percent. The mid-point of this range is
14 approximately 12.0 percent.
15 My risk premium analyses indicate that my DCF estimates produce a
16 premium over corporate bond yields that is below the average long-run risk
17 premium available from common stocks. The DCF return estimates provide a
18 premium over the return on corporate bonds that is considerably below the
19 average premium experienced by companies in Montana-Dakota's relative size
20 range. In addition, my examination of returns available on alternative equity
21 investments suggests that my DCF estimates generally are significantly below the
22 21.5 percent average return earned by the S&P 500 companies during the past five

1 years. Moreover, the DCF returns are far below the 29.4 percent average normal
2 returns earned by the Value Line Industrials in recent years.

3 **Q43. What rate of return on common equity do you recommend for Montana-**
4 **Dakota in this proceeding?**

5 A. My analyses indicate that an appropriate rate of return on common
6 equity for Montana-Dakota's South Dakota natural gas distribution operations at
7 this time would be **12.00 percent**. This recommended return reflects my
8 assessment that Montana-Dakota's overall risks are average relative to the proxy
9 group. A return of 12.00 percent is at the middle of the range for my Primary
10 DCF analysis and also is very close to the average for my Second-Stage Retention
11 Growth and Basic DCF analyses.

12 **Q44. Does this conclude your Prepared Direct Testimony?**

13 A. Yes.

Montana-Dakota Utilities Co.

General Economic Statistics

1971-2001

Year	Percentage Price Changes: Consumer Price Index	Percentage Price Changes: GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP (Billions)
1971	4.4%	5.0%	3.3%	1,128.6
1972	3.2%	4.3%	5.4%	1,240.4
1973	6.2%	5.6%	5.8%	1,385.5
1974	11.0%	9.0%	-0.6%	1,501.0
1975	9.1%	9.3%	-0.4%	1,635.2
1976	5.8%	5.7%	5.6%	1,823.9
1977	6.5%	6.4%	4.6%	2,031.4
1978	7.6%	7.1%	5.5%	2,295.9
1979	11.3%	8.3%	3.2%	2,566.4
1980	13.5%	9.2%	-0.2%	2,795.6
1981	10.3%	9.3%	2.5%	3,131.3
1982	6.2%	6.2%	-2.0%	3,259.2
1983	3.2%	4.0%	4.3%	3,534.9
1984	4.3%	3.7%	7.3%	3,932.7
1985	3.6%	3.1%	3.8%	4,213.0
1986	1.9%	2.2%	3.4%	4,452.9
1987	3.6%	3.0%	3.4%	4,742.5
1988	4.1%	3.4%	4.2%	5,108.3
1989	4.8%	3.8%	3.5%	5,489.1
1990	5.4%	3.9%	1.8%	5,803.2
1991	4.2%	3.6%	-0.5%	5,986.2
1992	3.0%	2.4%	3.0%	6,318.9
1993	3.0%	2.4%	2.7%	6,642.3
1994	2.6%	2.1%	4.0%	7,054.3
1995	2.8%	2.2%	2.7%	7,400.5
1996	3.0%	1.9%	3.6%	7,813.2
1997	2.3%	1.9%	4.4%	8,318.4
1998	1.6%	1.2%	4.3%	8,781.5
1999	2.2%	1.4%	4.1%	9,268.6
2000	3.4%	2.3%	4.1%	9,872.9
2001	2.8%	2.2%	1.2%	10,205.6
Average Rate of Change: 1/				
1971-2001	5.1%	4.4%	3.2%	7.6%
1981-2001	3.7%	3.2%	3.1%	6.1%
1991-2001	2.8%	2.1%	3.1%	5.5%

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

Source: *Economic Report of the President*, February 2002 and U.S. Department of Commerce, Bureau of Economic Analysis.

Montana-Dakota Utilities Co.

Mergent Bond Yield Averages
November 2000 - October 2002

		Average Corporate	Public Utility Bonds A-Rated	Public Utility Bonds Baa-Rated
2000	NOV	7.90	8.11	8.25
	DEC	7.65	7.84	8.01
2001	JAN	7.55	7.80	7.99
	FEB	7.50	7.74	7.94
	MAR	7.41	7.68	7.85
	APR	7.63	7.94	8.06
	MAY	7.69	7.99	8.11
	JUN	7.56	7.85	8.02
	JUL	7.51	7.78	8.05
	AUG	7.37	7.59	7.95
	SEP	7.54	7.75	8.12
	OCT	7.41	7.63	8.02
	NOV	7.32	7.57	7.96
	DEC	7.55	7.83	8.27
2002	JAN	7.38	7.66	8.13
	FEB	7.32	7.54	8.18
	MAR	7.57	7.76	8.32
	APR	7.49	7.57	8.26
	MAY	7.49	7.52	8.33
	JUN	7.36	7.42	8.26
	JUL	7.27	7.31	8.07
	AUG	7.06	7.17	7.74
	SEP	6.87	7.08	7.62
	OCT	7.07	7.23	7.99

Source: Mergent Bond Record.

Montana-Dakota Utilities Co.

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

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

Montana-Dakota Utilities Co.

Moody's Natural Gas Distribution Companies
Fiscal Year 2001 Operating Data

	Assets+ ($000,000)	Operating Revenues ($000,000)	Operating Income ($000,000)
AGL Resources Inc.	$3,465	$1,049	$209
Keyspan Corp.	$11,881	$6,633	$801
The Laclede Group, Inc.**	$1,018	$1,002	$72
Northwest Natural Gas Co.	$1,273	$650	$110
Peoples Energy Corp.	$2,728	$2,270	$162
WGL Holdings, Inc.	$2,114	$1,940	$140
High	$11,881	$6,633	$801
Median	**$2,421**	**$1,494**	**$151**
Low	$1,018	$650	$72
MDU Gas Distribution*	**$183**	**$255**	**$4**
MDU Resources Group, Inc.	$2,623	$2,224	$273
MDU Gas Distribution % of:			
- Proxy Company Median	**7.6%**	**17.1%**	**2.6%**
- MDU Resources Group, Inc.	7.0%	11.5%	1.5%

* Includes results for Great Plains Natural Gas Co. and Montana-Dakota Utilities Co.
** Assets as of June 30, 2002.
+ Assets as of September 30, 2002, unless otherwise noted.

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

Montana-Dakota Utilities Co.

Bond Ratings of
Moody's Natural Gas Distribution Companies

	Standard & Poor's	Moody's
AGL Resources Inc.	A-	A3
Keyspan Corp.	A+	A2
The Laclede Group, Inc.	A+	A3
Northwest Natural Gas Co.	A	A2
Peoples Energy Corp.	A-	Aa3
WGL Holdings, Inc.	AA-	Aa3
Median	A+/A	A2
MDU Resources Group	A+	A2

Source: C.A. Turner, *Utility Reports*, December 2002.

Montana-Dakota Utilities Co.

Moody's Natural Gas Distribution Companies
Dividend Yields
June 2002 - November 2002

		Stock Price June '02 - November '02				
		High	Low	Average	Dividend	Yield
AGL Resources Inc.	ATG	$ 24.50	$ 17.25	$ 20.88	$ 1.08	5.17%
Keyspan Corp.	KSE	$ 38.19	$ 27.41	$ 32.80	$ 1.78	5.43%
The Laclede Group, Inc.	LG	$ 24.58	$ 19.00	$ 21.79	$ 1.34	6.15%
Northwest Natural Gas Co.	NWN	$ 30.20	$ 23.46	$ 26.83	$ 1.26	4.70%
Peoples Energy Corp.	PGL	$ 39.40	$ 27.80	$ 33.60	$ 2.08	6.19%
WGL Holdings, Inc.	WGL	$ 26.70	$ 19.25	$ 22.98	$ 1.27	5.53%
Average						5.53%
Median						5.48%

Sources: America Online and S&P Stock Guide, November, 2002,

Montana-Dakota Utilities Co.

Projected Earnings Retention Growth Rates for Moody's Natural Gas Distribution Companies

	Value Line Forecast 2005-2007				
	EPS	DPS	ROE	Retention Rate	Retention Growth
AGL Resources Inc.	$ 2.10	$ 1.08	12.50%	48.57%	6.1%
Keyspan Corp.	$ 3.70	$ 1.87	13.50%	49.46%	6.7%
The Laclede Group, Inc.	$ 2.40	$ 1.65	15.00%	31.25%	4.7%
Northwest Natural Gas Co.	$ 2.60	$ 1.35	11.50%	48.08%	5.5%
Peoples Energy Corp.	$ 3.90	$ 2.24	11.00%	42.56%	4.7%
WGL Holdings, Inc.	$ 2.45	$ 1.30	12.50%	46.94%	5.9%
Average					5.6%
MDU Resources	$ 2.25	$ 1.10	10.00%	51.11%	5.1%

Source: *Value Line*, September 20, 2002 and November 15, 2002.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth Rate
Estimates for Moody's Natural Gas Distribution Companies

		2/3 Zacks 5-Yr Earnings Growth Est.	1/3 Retention Growth	Weighted Average
AGL Resources Inc.	ATG	9.83%	6.1%	8.58%
Keyspan Corp.	KSE	7.67%	6.7%	7.34%
The Laclede Group, Inc.	LG	3.50%	4.7%	3.90%
Northwest Natural Gas Co.	NWN	4.56%	5.5%	4.88%
Peoples Energy Corp.	PGL	4.33%	4.7%	4.45%
WGL Holdings, Inc.	WGL	4.00%	5.9%	4.62%
Average		5.6%	5.6%	**5.6%**
Median				**4.8%**

Sources: Zacks.com and page 4.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth DCF Calculation for Moody's 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.	5.17%	5.45%	8.58%	14.03%	1.0475	14.69%
Keyspan Corp.	5.43%	5.68%	7.34%	13.01%	1.0475	13.63%
The Laclede Group, Inc.	6.15%	6.30%	3.90%	10.20%	1.0475	10.68%
Northwest Natural Gas Co.	4.70%	4.84%	4.88%	9.72%	1.0475	10.18%
Peoples Energy Corp.	6.19%	6.36%	4.45%	10.81%	1.0475	11.32%
WGL Holdings, Inc.	5.53%	5.69%	4.62%	10.31%	1.0475	10.80%
Average	5.53%		5.63%	11.35%		**11.89%**
High				14.03%		14.69%
Median				10.56%		**11.06%**
Low				9.72%		10.18%

Montana-Dakota Utilities Co.

Basic DCF Calculation
for Moody's 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.	5.17%	5.49%	9.83%	15.32%	1.0475	16.05%
Keyspan Corp.	5.43%	5.69%	7.67%	13.36%	1.0475	13.99%
The Laclede Group, Inc.	6.15%	6.28%	3.50%	9.78%	1.0475	10.25%
Northwest Natural Gas Co.	4.70%	4.83%	4.56%	9.39%	1.0475	9.84%
Peoples Energy Corp.	6.19%	6.36%	4.33%	10.69%	1.0475	11.20%
WGL Holdings, Inc.	5.53%	5.67%	4.00%	9.67%	1.0475	10.13%
Average	5.53%		5.65%	11.37%		**11.91%**
High				15.32%		16.05%
Median				10.24%		**10.72%**
Low				9.39%		9.84%

Montana-Dakota Utilities Co.

Primary DCF Analysis
Computation of the Cost of Capital
for Moody's Natural Gas Distribution Companies

Growth Rate Estimate (g)	5.25%	6.25%
Current Dividend Yield (D/P)	5.53%	5.53%
Quarterly Model Dividend Yield Factor (1 + .625 g)	X 1.033	X 1.039
DCF Dividend Yield Component (Y)	5.71%	5.74%
Investor Required Return (Y + g)	10.96%	11.99%
Flotation Cost Adjustment	X 1.0475	X 1.0475
Cost of Capital	11.48%	12.56%
Mid-Point	**12.02%**	

Montana-Dakota Utilities Co.

Moody's Natural Gas Distribution Companies
2002 Capital Structures

	Long-Term Debt (Millions)	%	Preferred Stock (Millions)	%	Common Equity (Millions)	%	Total Capital
AGL Resources Inc.*	$ 845.0	46.88%	$ 225.5	12.51%	$ 732.0	40.61%	$ 1,802.5
Keyspan Corp.*	$ 5,261.5	65.48%	$ 83.8	1.04%	$ 2,689.5	33.47%	$ 8,034.8
The Laclede Group, Inc.**	$ 284.5	48.85%	$ 1.3	0.22%	$ 296.7	50.93%	$ 582.5
Northwest Natural Gas Co.*	$ 486.0	48.88%	$ 33.3	3.34%	$ 475.1	47.78%	$ 994.4
Peoples Energy Corp.**	$ 644.0	44.04%	$ -	0.00%	$ 818.4	55.96%	$ 1,462.5
WGL Holdings, Inc.**	$ 686.3	45.19%	$ 28.2	1.85%	$ 804.4	52.96%	$ 1,518.9
Average		**49.89%**		**3.16%**		**46.95%**	
Median		**47.86%**		**1.45%**		**49.36%**	
Montana-Dakota Utilities Co.		**44.67%**		**5.00%**		**50.30%**	

*Data are as of September 30, 2002.
** Data are as of June 30, 2002.

Source: Zacks.com

Montana-Dakota Utilities Co.

Common Equity Flotation Costs of Natural Gas Distribution/Transmission Companies 1992-2001

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%
Average 1992-2001					**4.85%**
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. NG02-__

Direct Testimony
of
Craig A. Keller, CPA

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

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

7 Q. Would you please describe your duties?

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

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

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

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 Public Utilities Commission.

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 and 2 show Montana-Dakota's balance sheet as of June 30, 2001 and 2002, with the balance sheets as of September 30, 2001 and 2002 on pages 19 and 20. Statement B consists of Montana-Dakota's income statement for the twelve months ended June 30 and September 30, 2002. Statement C reports Montana-Dakota's retained earnings statement as of June 30, 2002. These statements have been prepared from the Company's books and records that are maintained in accordance with the Federal Energy Regulatory

1 Commission (FERC) Uniform System of Accounts.

2 Statement G shows the utility capital structure of Montana-Dakota
3 as of June 30, 2002 and the projected average capital structure for 2002
4 and 2003. Statement G also includes the associated costs of debt,
5 preferred stock and common equity. This capital structure and the
6 associated costs serve as the basis for the overall rate of return requested
7 by Montana-Dakota in this rate filing of 10.303%. The basis for the
8 requested 12.00% return on common equity contained within the overall
9 requested rate of return is supported by the testimony of Dr. J. Stephen
10 Gaske.

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

13 A. Yes, they were.

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

15 A. Yes, they are.

16 Q. Would you please explain Rule 20:10:13:72, Statement G?

17 A. Pages 1 through 3 of Rule 20:10:13:72, Statement G summarizes
18 the actual average gas utility capital structure at June 30, 2002 and the
19 projected average capital structure and the related utility costs of capital
20 for 2002 and 2003. As shown on page 3, the components of the 2003
21 projected overall annual rate of return, which are used by Ms. Mulkern to
22 calculate the revenue requirement, are:

23

	Weighted Cost of Capital
Long Term Debt	4.033%
Preferred Stock	0.231%
Common Equity	6.039%
Required Rate of Return	10.303%

The debt costs reflected on Rule 20:10:13:73 Statement G, pages 1 through 3 represent the actual weighted embedded costs of the long-term debt at June 30, 2002 and that projected to be outstanding at December 31, 2002 and December 31, 2003 and are supported by Rule 20:10:13:73 Statement G, pages 4 through 9. 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 4 through 6. 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 4, supports the cost of Montana-Dakota's preferred stock capital, representing the

1 weighted cost of the issues at June 30, 2002 and projected to be
2 outstanding at December 31, 2002 and December 31, 2003.
3 Rule 20:10:13:75, Statement G, pages 1 through 3, supports the
4 Company's average utility common equity balance at June 30, 2002, and
5 the projected average balances for 2002 and 2003.
6 Q. What does Rule 20:10:13:73, Statement G, pages 1 through 6 support?
7 A. Page 1 is a summary showing the Company's long-term debt at
8 June 30, 2002 and average cost of debt. Page 2 shows the projected
9 average long-term debt and costs for 2002 and page 3 shows the same
10 information for projected 2003. Page 4 shows the cost and the debt
11 balance by issue at June 30, 2002. Pages 5 and 6 show the projected
12 December 2002 and 2003 balances by issue.
13 Q. How did you derive the projected cost of debt as for 2002 and 2003?
14 A. The projected cost of debt for 2002 and 2003 is based upon the
15 yield to maturity of each debt issue outstanding.
16 Q. Would you please describe Statement G, Rule 20:10:13:73, pages 7
17 through 9 and explain the amortization method utilized?
18 A. Pages 7 through 9 show the detail by issue of the annual
19 amortization of net discounts (losses) on advance purchases of debt that
20 are necessary to meet sinking fund requirements. For this proceeding,
21 the amortization has been computed on a straight-line basis over the
22 remaining life of the issues, the same calculation as is used by the
23 Company for accounting purposes.

1 Q. What does Rule 20:10:13:74, Statement G show?

2 A. Pages 1 through 3 present the preferred stock balances at June
3 30, 2002 and the projected average balances for December 2002 and
4 2003. The anticipated weighted average cost of preferred stock is also
5 shown. Page 4 sets forth the various preferred stock issues outstanding
6 at June 30, 2002.

7 Q. What does Rule 20:10:13:75, Statement G, pages 1 through 5 show?

8 A. Pages 1 through 3 present the common equity balances at June
9 30, 2002 and the projected average balances for 2002 and 2003 including
10 the projected changes in the balances each year. Pages 4 and 5 depict
11 the monthly issuance of common stock and associated costs from
12 January 1997 through June 2002.

13 Q. What does Rule 20:10:13:76, Statement G, Schedule G-1, page 1 show?

14 A. Page 1 indicates that, during the five-year period preceding
15 December 31, 2001, MDU Resources Group, Inc. issued 17.2 million
16 additional shares of common stock in connection with a three-for-two
17 stock split. Also during that period, the number of authorized shares of
18 common stock was increased from 75 million at a par value of $3.33 to
19 150 million with a par value of $1.00.

20 Q. Would you please describe Rule 20:10:13:77, Statement G, Schedule
21 G-2?

22 A. This schedule presents various financial and market data relative to
23 the Company's common stock for the years 1997 through 2001, and for

1 each month of the twelve month period ended June 30, 2002.

2 Q. Would you please describe Rule 20:10:13:78, Statement G, Schedule

3 G-3?

4 A. This schedule shows that the reacquisition activity for bonds and a

5 summary of scheduled retirements of preferred stock for the 5 years

6 ended June 30, 2002.

7 Q. Does this conclude your direct testimony?

8 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. NG02-

Direct Testimony
of
Rita A. Mulkern

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

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

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

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

7 Q. Would you please describe your duties as Regulatory Analysis Manager?

8 A. I am responsible for the preparation of cost of service studies, fuel
9 cost adjustments, purchased gas cost adjustments and gas tracking
10 adjustments in each of the jurisdictions in which Montana-Dakota operates.

11 Q. Would you please describe your education and professional background?

12 A. I graduated from North Dakota State University in 1981 with a
13 Bachelor of Arts degree with majors in Economics and Business
14 Administration and a minor in Statistics. I joined Montana-Dakota in July
15 1981 as a Regulatory Statistician, became Cost of Service Supervisor in
16 1986 and assumed my current position in 1999.

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

18 A. Yes, I have presented testimony before the Public Service
19 Commissions of Montana, North Dakota, and Wyoming and the South

1 Dakota Public Utilities Commission and have filed testimony with the
2 Minnesota Public Utilities Commission.
3 Q. Are you familiar with the territory served by Montana-Dakota and the
4 facilities of the Company utilized in providing gas service?
5 A. Yes, I am.
6 Q. Are you familiar with the books and records of Montana-Dakota and the
7 manner in which they are kept?
8 A. Yes. Montana-Dakota's books and records are kept in accordance
9 with the Federal Energy Regulatory Commission (FERC) Uniform System
10 of Accounts.
11 Q. What is the purpose of your testimony in this proceeding?
12 A. The purpose of my testimony is to present the per books cost of
13 service for the twelve months ended June 30, 2002, the projected cost of
14 service for 2002 and 2003 and the calculation of the revenue deficiency.
15 Q. What statements, schedules and exhibits are you sponsoring?
16 A. I am sponsoring Statements D through F, Statements H through M,
17 Statements P through R and Exhibit No.___(RAM-1).
18 Q. Were these statements and exhibits prepared by you or under your direct
19 supervision?
20 A. Yes, they were.
21 Q. What were the results of South Dakota gas operations for the twelve
22 months ending June 30, 2002?
23 A. Statement M, pages 1 and 2 show the per books income statement
24 and rate base for total Company and South Dakota gas operations. The

1 details for each line item, i.e. sales revenue, other revenue, plant in service,
2 etc., are included in the Statements.
3 Q. How was the per books cost of service allocated to South Dakota?
4 A. The Company utilizes a jurisdictional accounting system that directly
5 assigns and/or allocates every item of revenue, expense and rate base to
6 the jurisdictions as part of the regular accounting process on a monthly
7 basis, resulting in jurisdictional results on an ongoing basis. The allocation
8 methods and procedures are the same as have previously been adopted by
9 this Commission and are based on the principle of assigning and/or
10 allocating costs to the cost causer. The total Company and South Dakota
11 information included in the Statements is from the books and records of the
12 Company.
13 Q. What test period are you using to determine the revenue requirement?
14 A. The revenue requirement is based on a projected average 2003 test
15 year. Since the rates will likely become effective in mid-2003, an average
16 2003 cost of service will best match the cost and customer levels at the
17 time that the rates will go into effect. The rates from this proceeding will be
18 in effect in 2003 and the closer that revenues, expenses and rate base
19 reflect levels to be experienced in 2003, the better the match will be and the
20 better opportunity Montana-Dakota will have to earn its authorized return.
21 Q. Would you describe the development of the projected cost of service for
22 2002 and 2003?
23 A. The projected 2002 and 2003 cost of service is summarized in
24 Statement M, with the supporting detail contained in Statements D through

1 L. The revenues and expenses reflect the annual level that will be
2 experienced when the new rates become effective. Likewise, the rate base
3 reflects average 2002 and 2003 plant and related balances.
4 Q. Would you describe the development of the projected revenues and
5 expenses?
6 A. Sales and transportation revenues are shown on Statement I, page 1
7 and reflect projected sales volumes for all classes. The projected
8 residential and firm general service sales volumes for 2002 and 2003 were
9 based on actual historical data. The 2002 forecast reflects the historical
10 weather normalized average use per customer and annualized customer
11 levels. The forecast for 2003 uses the historical weather normalized
12 average use per customer and projected customer increases for 2003. The
13 number of firm customers is projected to grow at approximately 2.0 percent
14 per year and the projected volumes reflect continuing conservation of 1.0
15 percent per year. The projected firm revenues were calculated based on
16 the projected volumes and number of customers using the currently
17 effective rates inclusive of the PGA effective December 1, 2002, exclusive
18 of the surcharge adjustment.
19 The sales and transportation volumes for the U.S. Air Force, small
20 interruptible and large interruptible classes were projected on a customer-
21 by-customer basis and the revenues were calculated using current rates.
22 Miscellaneous revenues, shown on Statement I, page 2, are
23 projected to remain at the June 30, 2002 level.

1 Q. Would you describe the development of the operation and maintenance
2 expenses?
3 A. Yes. The operation and maintenance expenses are in Statement H.
4 Pages 1 and 2 of Statement H, Schedule H-1 summarize the projected
5 2002 and 2003 operation and maintenance (O&M) expenses, with the
6 details provided on pages 3 through 12. The cost of gas, shown on page 3,
7 uses the projected sales volumes, adjusted for losses, and current gas
8 costs effective December 1, 2002. The loss factor of 0.86% was calculated
9 by comparing the gas volumes delivered into the town border stations in
10 South Dakota to the gas volumes sold and dk transported to customers on
11 a billing cycle basis for the twelve-month periods ending July 31, August 31
12 and September 30, 2002. The difference between deliveries at the town
13 border station and deliveries to customers (sales) is the lost and
14 unaccounted for gas, which is then expressed as a percentage of total
15 deliveries and reflects an average for those three periods.
16 Labor expense is shown on page 4, with actual labor expense for the
17 twelve months ended June 30, 2002 as the starting point. The labor
18 expense for 2002 and 2003 was developed by applying the projected
19 percentage increase in total Company labor costs to the per books South
20 Dakota labor expense. The projected labor costs were based on the actual
21 and budgeted labor amounts for 2002, adjusted to reflect a three year
22 average amount for the bonuses and commissions and amounts to a 4.83
23 percent increase for 2002. A labor increase of 7.66 percent was applied to
24 the 2002 labor expense to arrive at the 2003 labor expense.

1 Benefits expense consists of medical/dental insurance, pension
2 expense, the Supplemental Income Security Plan (SISP), 401K, post-
3 retirement, workers compensation and other benefits. Each of these items,
4 excluding the other benefits, was projected individually for 2002 using the
5 2002 actual and budgeted amounts and applying the projected increase to
6 each type of benefit. Benefits expense for 2003 reflects a projected
7 increase by type of benefit. Mr. Espeland discusses the inclusion of the
8 SISP expense in his testimony.
9 Insurance expense, as shown on page 6, reflects the current
10 insurance level for 2002, which is a 14 percent increase over the June 30,
11 2002 level and a projected 28 percent increase for 2003 based on current
12 information.
13 Postage expense for 2002 and 2003 reflects the annualized postage
14 increase that became effective on June 30, 2002.
15 Industry dues are projected for 2002 and 2003 on page 8.
16 Page 9 shows the projected level of advertising expense for 2002
17 and 2003. Promotional advertising has been eliminated, pursuant to past
18 Commission policy.
19 Q. Is the Company requesting the inclusion of institutional advertising in this
20 case?
21 A. Montana-Dakota is seeking to include institutional advertising, as it
22 believes such advertising is beneficial to customers. As a corporate citizen,
23 Montana-Dakota needs to be active in the communities that it serves. Our
24 communities expect nothing less and advertising in the local newspapers,

1 school yearbooks, programs, etc., is a necessary part of being active in the
2 community. This advertising benefits the community and the customers in
3 that community, thus serving the public interest.
4 Q. What other O&M expenses are included in Statement H?
5 Regulatory commission expense is shown on page 10. The
6 projected 2002 and 2003 level incorporates the projected rate case
7 expenses from this case amortized over a three-year period and the
8 ongoing level of regulatory commission expense.
9 Pages 11 and 12 show the O&M expenses not specifically
10 identifiable or calculated as described above, adjusted for the effects of
11 inflation. A 2.68 percent inflation factor based on the increase in the
12 consumer price index for June 2000-June 2002 was applied to the
13 expenses not specifically identifiable.
14 Q. Would you describe the calculation of depreciation expense?
15 A. Yes. Depreciation expense for projected 2002 and 2003 is shown in
16 Statement J, page 1 and was calculated using projected plant in service
17 and the current depreciation rates, as shown on Statement J, page 2. The
18 composite depreciation rates and calculation are shown on Statement E,
19 pages 2 and 3.
20 Q. Would you describe the calculation of taxes other than income?
21 A. Yes. Taxes other than income are shown in Statement L. Ad
22 valorem taxes were calculated using the projected 2002 and 2003 plant in
23 service and applying the effective tax rates based on the 2001 ratio of ad
24 valorem taxes to plant.

1 The accumulated deferred income tax balances are included in
2 Statement K, page 12 and were derived by adding the deferred income
3 taxes related to property for 2002 and 2003 to the 2001 balance from page
4 9 and calculating average balances.
5 The accumulated investment tax credit balances were derived by
6 subtracting the projected amortization for 2002 and 2003 from the 2001
7 balance and calculating average balances.
8 Q. What does Exhibit No.____(RAM-1) show?
9 A. Exhibit No.____(RAM-1), page 1, which is identical to Statement M,
10 page 3, shows the per books June 30, 2002 and projected 2002 and 2003
11 income statement. Page 2 shows the per books and projected average rate
12 base for 2002 and 2003 and is identical to Statement M, page 4, and page
13 3 shows the calculation of the revenue deficiency of $2,173,724 based on
14 the projected 2003 operating income and rate base and using the overall
15 rate of return of 10.303% from Statement G, page 3.
16 Q. Does that complete your testimony?
17 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	Per Books	2002	2003
Operating Revenues			
Sales	$30,893,615	$36,478,724	$36,834,005
Transportation	453,665	360,948	352,589
Other	147,425	147,425	147,425
Total Revenues	31,494,705	36,987,097	37,334,019
Operating Expenses			
Operation and Maintenance			
Cost of Gas	21,351,949	26,720,886	26,946,077
Other O&M	6,262,739	6,672,199	7,292,809
Total O&M	27,614,688	33,393,085	34,238,886
Depreciation	1,607,620	1,685,586	1,837,574
Taxes Other Than Income	719,996	720,517	775,067
Current Income Taxes	546,059	(922,519)	(620,957)
Deferred Income Taxes	(107,226)	1,225,620	679,817
Total Expenses	30,381,137	36,102,289	36,910,387
Operating Income	$1,113,568	$884,808	$423,632
Rate Base	$14,829,782	$14,921,823	$17,793,768
Rate of Return	7.509%	5.930%	2.381%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	6/30/02	2002	2003
Gas Plant in Service	$38,932,377	$39,868,312	$43,732,810
Accumulated Reserve for Depreciation	22,878,024	23,505,786	24,631,780
Net Gas Plant in Service	16,054,353	16,362,526	19,101,030
CWIP in Service Pending Reclassification	264,640		
Total Gas Plant in Service	16,318,993	16,362,526	19,101,030
Additions			
Materials and Supplies	290,358	253,531	253,531
Prepayments	50,818	48,803	55,121
Other	174,494	166,563	150,699
Total Additions	515,670	468,897	459,351
Total Before Deductions	$16,834,663	$16,831,423	$19,560,381
Deductions			
Accumulated Deferred Income Taxes	$1,840,886	$1,786,289	$1,667,062
Accumulated Investment Tax Credits	39,658	33,248	18,324
Customer Advances	124,337	90,063	81,227
Total Deductions	2,004,881	1,909,600	1,766,613
Total Rate Base	$14,829,782	$14,921,823	$17,793,768

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - SOUTH DAKOTA

	2003 Before Additional Revenue Requirements	Additional Revenue Requirements	Pro Forma Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$36,834,005	$2,173,724	$39,007,729
Transportation	352,589		352,589
Other	147,425		147,425
Total Revenues	37,334,019	2,173,724	39,507,743
Operating Expenses			
Operation and Maintenance			
Cost of Gas	26,946,077		26,946,077
Other O&M	7,292,809		7,292,809
Total O&M	34,238,886		34,238,886
Depreciation	1,837,574		1,837,574
Taxes Other Than Income	775,067	3,261	778,328
Current Income Taxes	(620,957)	760,803	139,846
Deferred Income Taxes	679,817		679,817
Total Expenses	36,910,387	764,064	37,674,451
Operating Income	$423,632	$1,409,660	$1,833,292
Rate Base	$17,793,768		$17,793,768
Rate of Return	2.381%		10.303%

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

Before the Public Utilities Commission of South Dakota

Docket No. NG02-___

Direct Testimony
of
Richard A. Espeland

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

2 A. Yes, my name is Richard A. Espeland. My business address is 918
3 East Divide Avenue, Bismarck, North Dakota 58506.

4 Q. What is your position?

5 A. I am Vice President—Human Resources for MDU Resources
6 Group, Inc. (MDU Resources).

7 Q. What are your duties and responsibilities with MDU Resources?

8 A. I have overall responsibility for the Human Resource functions
9 throughout the corporation. The primary areas include employment, total
10 compensation (general and executive compensation and benefits),
11 training and development, employee relations and employee
12 communications.

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

14 A. In 1966, I received a Bachelor of Arts degree from the University of
15 North Dakota in Business Administration with a major in Personnel
16 Management. In 1981, I received a Masters degree from the University of
17 North Dakota in Public Administration.

1 Upon graduating from college, I spent four years in the U.S. Army.
2 Prior to my employment with MDU Resources I was employed by the City
3 of Grand Forks, the State of North Dakota and North American Coal
4 Corporation, all in the human resources area.
5 In December 1989, I joined MDU Resources as Human Resource
6 Manager, retaining that position until August 2000 when I was elected
7 Vice President—Human Resources.
8 I am a member of the Society for Human Resource Management
9 and the Central Dakota Human Resource Association. I have spoken on
10 retirement and employee benefit issues on many occasions at national
11 conferences in Boston, Orlando, Chicago and San Francisco.
12 Q. What is the purpose of your testimony?
13 A. The purpose of my testimony is to address the Supplemental
14 Income Security Plan (SISP), the cost of which has been included by
15 Company witness Mulkern in the cost of service in this proceeding.
16 Q. What are your duties and responsibilities relative to the SISP?
17 A. I am the Plan Administrator assigned the responsibility by the
18 Board of Directors for the management of the plan, plan design, eligibility,
19 interpretation, communication and benefits administration.
20 Q. Would you briefly describe what the SISP is and what it is designed to do.
21 A. The SISP is a plan that provides a supplemental pension benefit to
22 key employees. It was designed to provide equitable retirement benefits
23 for key employees and to attract and retain key employees in a number of
24 positions within the Company. A common practice for retirement planning

1 is to look at the level of "replacement" income at retirement. We try to
2 provide 50% to 80% as a target level – the 80% at lower income levels,
3 and at least 50% at the higher income levels. Also, this is only one part of
4 an employee's compensation, so the targets are set as part of an overall
5 view of compensation.
6 Q. How does the SISP fit into MDU's overall compensation plans, and how
7 are they determined for executives?
8 A. First, when we – the Board of Directors and executive management
9 – design and implement compensation and benefit plans, we look at the
10 "Total Compensation" picture, not just one element by itself. This includes
11 base salary, incentive compensation, general benefits, and any other
12 generally recognized and appropriate plans like the SISP.
13 The Compensation Committee of the Board of Directors is
14 responsible for determining the compensation of the Company's executive
15 officers. The Committee is composed entirely of non-employee Directors
16 and they meet several times each year to review and determine
17 compensation for the executives. The committee seeks appropriate
18 compensation levels that succeed in both attracting and motivating high
19 quality employees. To implement this philosophy, the Committee
20 analyzes trends in compensation among comparable companies and
21 relies in part on information and recommendations by an independent
22 compensation consultant – currently Towers Perrin - in making their
23 decision.
24 Q. Who is Towers Perrin?

1 A. Towers Perrin is one the worlds largest management consulting
2 firms. The firm's clients include three-fourths of the Fortune 1000 largest
3 U. S. companies which includes MDU Resources. The firm provides
4 executive compensation advice and helps companies design and manage
5 executive compensation programs.
6 Towers Perrin provides a report to MDU that includes competitive
7 market data from hundreds of companies throughout the region and nation
8 that have similar types of positions and responsibilities. This information
9 is proprietary to Towers Perrin, and is provided for MDU's internal use
10 only.
11 Q. Without compromising the proprietary nature of the information received
12 from Towers Perrin, could you provide more detail on the scope of its
13 review and the methods it uses?
14 A. Yes. The overall approach and methods used to report on the
15 compensation information begins with a request from MDU for Towers
16 Perrin to update the analysis of our executive compensation programs.
17 Specifically, MDU requests a current market assessment of competitive
18 pay levels for base salary, total annual cash (base salary plus annual
19 bonus) and total direct compensation (total annual cash plus the expected
20 value of long-term incentives) for all identified management positions, and
21 an updated salary grade structure based on the above competitive
22 analyses.
23 Q. What is the process or steps Towers Perrin uses to conduct this analysis?

1 A. Towers Perrin provides a consistent approach each year to insure
2 that the comparative data is valid over time. This includes confirming
3 positions to be included in the analysis, identifying material changes to
4 MDU's jobs – if any, updating current compensation information, gathering
5 and analyzing relevant salary survey data, validating survey data, and
6 summarizing and reporting results.
7 Q. Do they use only their own salary data base, or several?
8 A. Towers Perrin considers data from both general industry and
9 industry specific surveys. Specifically, for the general industry data they
10 included their own data - Towers Perrin's Executive Compensation Data
11 Bank, and the Executive Compensation Service's Top Management
12 Report. For industry specific data they included the Edison Electric
13 Institute Executive Compensation Survey (which they compile for EEI), the
14 American Gas Association's compensation survey, the Effective
15 Compensation, Inc. Survey and several others.
16 Q. When Towers Perrin provided their report this year, how did MDU
17 compare to the competitive salary market data?
18 A. The competitive position of Montana-Dakota, and our other
19 companies, was well below the market. I mentioned earlier that we look at
20 all parts of compensation to determine what is competitive and fair. The
21 "Competitive Analysis" by Towers Perrin, for "Total Direct Compensation"
22 (which includes base salary, annual incentives, and long-term incentives),
23 reported that we were paying an average of less than 86% of the 50th

1 percentile for all executives. The Towers Perrin report clearly indicates
2 our conservative approach to compensation.
3 Q. How does the Compensation Committee of the Board of Directors use the
4 information it receives from Towers Perrin?
5 A. When the Compensation Committee develops MDU's "Total
6 Compensation" plan, it focuses on the competitive salaries and benefits,
7 including the SISP, that are necessary to maintain our ability to attract,
8 retain, and appropriately reward the individuals needed to provide reliable,
9 safe, efficient, and cost effective service to our customers.
10 Q. Who are the "key employees" you refer to who are participants in SISP?
11 A. "Key employees" are officers and senior managers of MDU
12 Resources and Montana-Dakota who plan for the future, implement
13 appropriate strategies for the Company and see how to reduce costs,
14 streamline the organization, and implement new technologies to maintain
15 and increase the efficiencies of the Company while keeping the rates
16 stable and competitive in the industry. I would like to note that all our
17 employees are key to the company and our customers. However, in this
18 context, "Key" has a narrow definition and is a common reference used in
19 executive compensation.
20 Q. When was the SISP implemented?
21 A. The SISP was implemented in 1982.
22 Q. Montana-Dakota has not previously sought rate recovery of the SISP.
23 Would you please explain why?

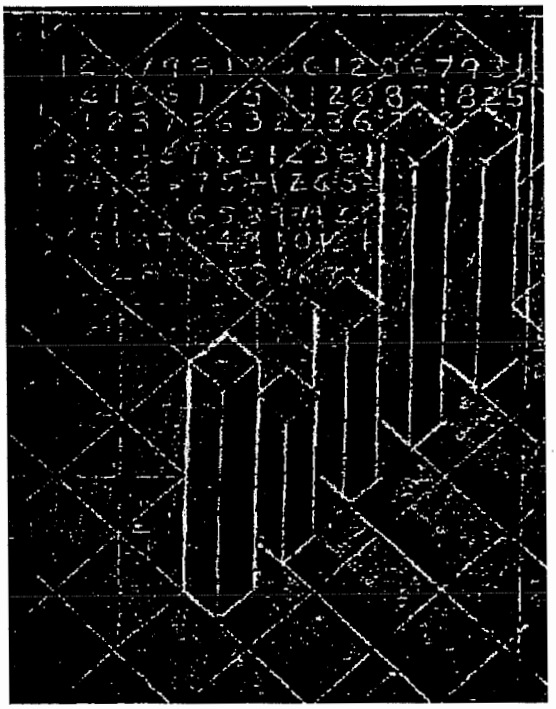
1 A. Yes. When the SISP was implemented in 1982, Supplemental
2 Employee Retirement Plans (SERPs) such as SISP were visionary plans
3 that were new to the utility industry. They were not common at that time
4 anywhere within the industry and it was unknown if they would become an
5 accepted part of executive compensation. In the intervening years since
6 then, and particularly in the last few years, for reasons I will describe later,
7 SERPs have become a common and accepted compensation benefit for
8 executives of utilities and related companies. Such plans provide a
9 supplemental pension benefit designed to provide equitable retirement
10 benefits necessary to attract and retain key employees.
11 Q. What information do you have showing that SERPs have become a
12 common part of executive compensation?
13 A. Recent studies by consulting firms such as the Hay Group indicated
14 that 74% of the companies offer non-qualified retirement plans as part of
15 their executive compensation package. Similarly, Clark/Bardes
16 Consulting has also reported that about 75% of the companies, including
17 utilities, have non-qualified plans. These studies clearly indicate the
18 common practice of providing this type of benefit. In addition, the Hay
19 survey indicates that almost two-thirds of such plans (64%) offer
20 unreduced early retirement prior to age 65. Our SISP does not allow for
21 early retirement - again a conservative approach by MDU. I have included
22 the relevant pages from the above studies as Exhibit No. ___ (RAE-1).
23 Q. Why have non-qualified retirement plans become a common part of
24 executive compensation?

1 A. These types of plans have become necessary due to various
2 changes in federal regulations, social security benefits, and employment
3 practices. Those changes have adversely affected the potential
4 retirement benefits of key employees of companies such as MDU. In
5 order to attract, retain, and provide equitable benefits for key employees,
6 SERPs, such as Montana-Dakota's SISP, have become necessary to
7 replace or supplement retirement benefits that were lost or reduced as a
8 result of these changes.
9 Q. Please describe the various changes in federal regulations that have
10 adversely affected retirement plans for key employees.
11 A. In the early 1980s, defined benefit pension plans could provide
12 benefits in consideration of up to $225,000 in salary. That limit was
13 reduced in the mid 1980s to $150,000 maximum covered compensation,
14 therefore, reducing the benefit eligibility and pension benefits provided by
15 one-third. This compensation limit has slowly increased to the current
16 $200,000 level, but certainly not at a pace equal to general wage inflation.
17 In addition, the 401(k) Plan regulations limit the employee contribution to
18 $11,000. (The effect is the employee with $50,000 in annual income can
19 contribute 22% of salary while senior executives are generally limited to
20 10% or less of salary).
21 Q. What changes in social security benefits have adversely affected key
22 employees?
23 A. The social security benefits, while increasing over the years, have
24 not kept pace with general wage inflation and benefits. Such benefits, as

1 a percentage of income provided to higher income levels, are significantly
2 less than at lower income levels.
3 Q. How do the overall retirement benefits for employees included in the SISP
4 compare with the retirement benefits for those employees not included in
5 the SISP?
6 A. When compensation and benefit programs are designed and
7 implemented, they must be looked at in the context of total benefits. To
8 put the retirement programs in perspective, I have prepared Exhibit No.
9 ___(RAE-2) which reflects the retirement programs available to
10 employees, including SISP. As you will note from the graph, at the lower
11 income levels, the replacement income through retirement programs is
12 about 80 percent. This includes Social Security, the Defined Benefit
13 Pension Plan, and the Company match to employee contributions under
14 the 401(k) Plan. As you move up the income scale, the percentage of
15 income replaced by retirement plans significantly decreases based on
16 retirement plan design requirements and government limitations on
17 retirement plans. The SISP, as a supplemental plan, has been designed
18 to replace some—but not all—of the income that is not replaced by Social
19 Security, the Defined Benefit Pension Plan, and the 401(k) Plan. At the
20 higher income levels only about 50 percent of the annual income is
21 replaced, compared to 80 percent at the lower income levels.
22 Q. Does the SISP benefit last as long as the other retirement benefits you've
23 noted?

1 A. No, it does not. The retirement benefits under SISP are payable
2 over 15 years beginning at age 65 and not the remaining lifetime of the
3 individual (which currently is about 20 years after retirement). Social
4 Security, the Defined Benefit Pension, and the 401(k) Plan income
5 projections meanwhile cover a retired employee's lifetime.
6 Q. Should the costs of Montana-Dakota's SISP be included in rates?
7 A. Yes, they should be. The SISP is a common type of benefit
8 provided in today's business environment. The combined replacement
9 income from all retirement plans when taken together is equitable,
10 reasonable and justifiable. The SISP recognizes the contributions of key
11 employees whose abilities and vision have enabled Montana-Dakota to
12 streamline operations, reduce costs and employee numbers, implement
13 new technologies and, most importantly to the ratepayer, to keep
14 Montana-Dakota's rates competitive. In addition, our Board of Directors
15 and our management team have the responsibility to determine the level
16 of "Total Compensation" that is competitive and appropriate and then to
17 determine the most cost effective methods to deliver the compensation.
18 By providing a supplemental retirement benefit like SISP, we can provide
19 a competitive retirement benefit at a lower cost than if we were to increase
20 the executives base salary, which is included in rates, to the level
21 necessary for them to attain the same level of retirement income.
22 Q. Does this complete your direct testimony?
23 A. Yes, it does.

A 2001 SURVEY



HayGroup

Survey Highlights

Perquisites

- Cell phones have now joined cars/car allowances as the most prevalent perquisites.
- In most perquisite categories, prevalence is significantly higher for the CEO.
- Employment Guarantee-type perquisites (employment contracts, Golden parachutes, severance) continue as the fastest growing perquisites.
- Executive Flex Plans, while on the increase, are still not widely offered, despite their flexibility for executives.

Non-Qualified Plans

- 74% of all participants sponsor some form of nonqualified retirement and/or deferred compensation arrangement.
- Prevalence of such plans varies substantially by size of organization from 56% (1,000 or fewer employees) to 91% (over 10,000 employees).
- Prevalence was considerably higher among industrial organizations (76%) and financial service organizations (90%) than among general service organizations (59%).
- Prevalence of plans was substantially higher for taxable organizations (77%) than among tax-exempt organizations (58%).
- CEOs are generally more likely to have plans than other top officers.
- Almost two-thirds of such plans (64%) offer unreduced early retirement prior to age 65.
- Target retirement ratios fall into the 50% to 70% range for three-fourths of the plans reporting, an increase over prior surveys.
- Funding, in the context of non-qualified plans, is prevalent in 77% of the plans, a major increase over prior surveys.

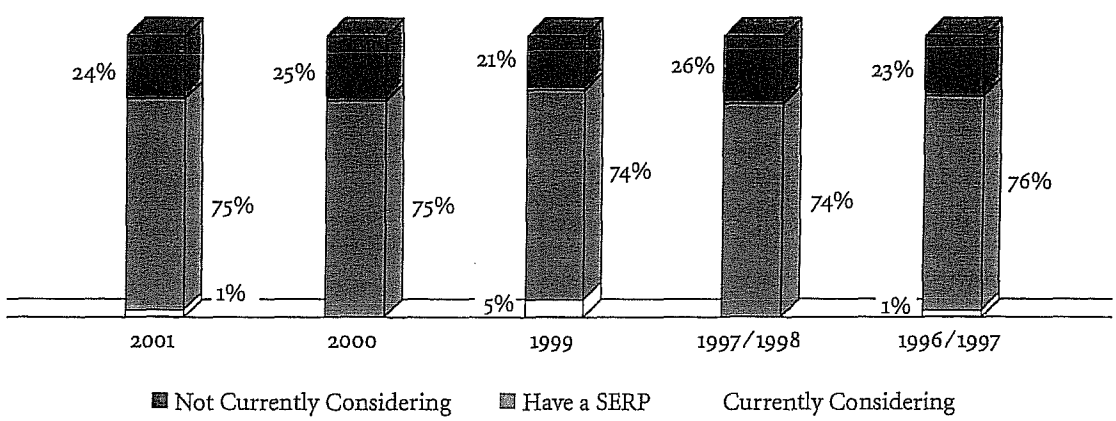
INTRODUCTION

For purposes of the Survey, a Supplemental Executive Retirement Plan ("SERP") is a nonqualified retirement plan under which the *employer* provides an additional retirement benefit to the employee. A SERP may be characterized as either a nonqualified defined contribution plan or a nonqualified defined benefit plan. Often, a SERP is tied in some fashion to the benefits provided under the employers' qualified retirement plans.

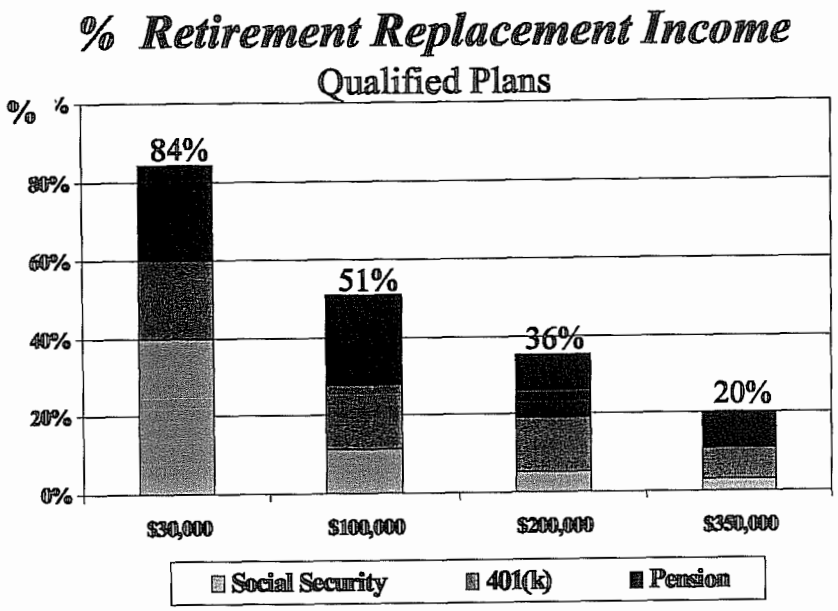
Approximately 75% of Respondents have adopted a SERP to provide benefits to executives in excess of amounts limited by qualified plan restrictions, holding steady from 2000. The primary reason for adopting a SERP is the Omnibus Budget Reconciliation Act ("OBRA") of 1993 which lowered the limit on compensation used for qualified pension calculations to $150,000 (currently indexed to $170,000 in 2001) (Internal Revenue Code [IRC] §401(a)(17)).

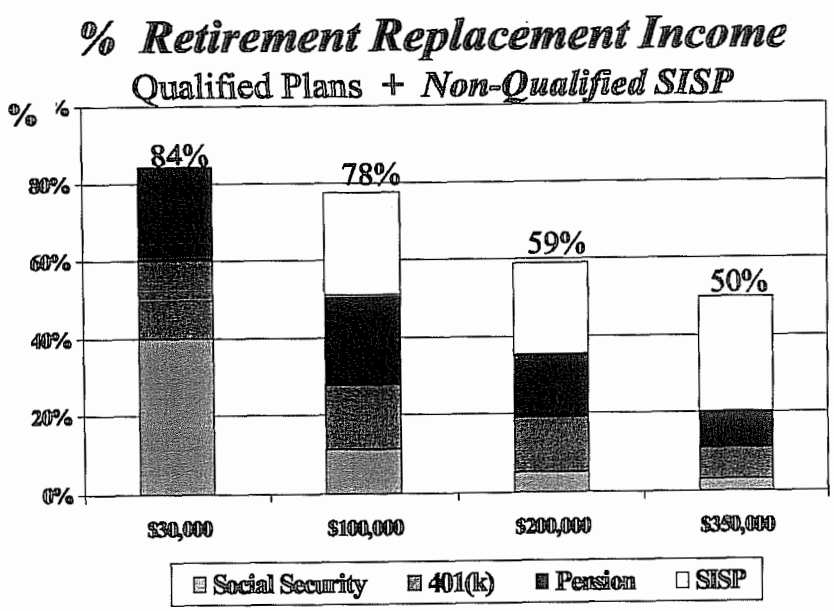
PLAN PREVALENCE

SERP PREVALENCE



SERP PREVALENCE			
Up to $2.5 Billion in Annual Revenue	Above $2.5 Billion in Annual Revenue	All Financial Institutions	All Surveyed Companies
67%	74%	84%	75%


% Retirement Replacement Income
Qualified Plans
%
80%
60%
40%
20%
0%
84%
51%
36%
20%
$30,000
$100,000
$200,000
$350,000
Social Security
401(k)
Pension


% Retirement Replacement Income
Qualified Plans + Non-Qualified SISP
%
80%
60%
40%
20%
0%
84%
78%
59%
50%
$30,000
$100,000
$200,000
$350,000
Social Security
401(k)
Pension
SISP

Docket No. _____

BEFORE THE

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

Direct Testimony

of

Russell A. Feingold

on behalf of

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.

December, 2002

Docket No. _____

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DIRECT TESTIMONY OF RUSSELL A. FEINGOLD

Background And Qualifications

Q. Please state your name and business address.

A. My name is Russell A. Feingold and my business address is 200 Wheeler Road, Suite 400, Burlington, Massachusetts 01803. I am employed by Navigant Consulting, Inc. ("NCI") as a Managing Director and lead its Regulation & Litigation Support Practice. I have been employed by NCI since January 1997.

Q. Please describe in more detail the business activities of NCI.

A. NCI has served the electric and natural gas industries since 1983. We offer a wide range of consulting services related to information technology, process/operations management, business strategy development, and marketing and sales designed to assist our clients in a business environment of changing regulation, increased competition and evolving technology. From an industry-wide perspective, NCI has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide

variety of client assignments. NCI has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over 27 years of experience in the utility industry, the last 25 years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. I have prepared and presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and several state and provincial regulatory commissions and have spoken widely on issues and activities dealing with the pricing and marketing of gas and electric utility services.

Further background information summarizing my education, presentation of expert testimony and other industry-related activities is included in Appendix A to my testimony.

Q. Have you previously testified on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company"), a Division of MDU Resources Group, Inc.?

A. Yes, I have. I previously testified on behalf of Montana-Dakota before the Public Service Commission of Montana in Docket Nos. 87.12.77, 88.11.53, and D2002.5.59 on the subjects of gas rate design and related ratemaking mechanisms and gas marginal cost analyses, before the Public Service Commission of North Dakota in Case No. PU-399-02-183, and before the Public Service Commission of Wyoming in Docket No. 30013-GR-02-127, on the subjects of gas rate design and related ratemaking mechanisms.

Purpose

Q. For what purpose has Montana-Dakota retained NCI?

A. NCI has been retained by Montana-Dakota as a consultant in the area of utility rate design and related regulatory matters for its gas operations.

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

A. The purpose of my direct testimony is to address certain gas rate design concepts that the Company has evaluated in formulating its rate proposal in this

1 proceeding. Specifically, I will discuss the conceptual underpinnings and
2 industry-wide trends associated with the Company's proposal to enhance the
3 recovery of its gas distribution margin through rate design. In addition, I will
4 provide an overview and analysis of an alternative ratemaking mechanism that
5 Montana-Dakota could apply to its heat sensitive classes of service.
6
7 **Q. What exhibits are you sponsoring in this proceeding?**
8
9 A. I am sponsoring the following exhibits:
10 • Exhibit No. __ (RAF-1), Survey of Monthly Customer Charges of North
11 American Gas Distribution Utilities
12 • Exhibit No. __ (RAF-2), Distribution Delivery Stabilization Mechanism
13
14 **Proposed Rate Structure Changes**
15
16 **Q. Why has Montana-Dakota chosen to propose certain rate design changes**
17 **that will better provide for the recovery of its authorized level of**
18 **distribution margin?**
19
20 A. The Company has chosen to address this issue in order to provide greater
21 predictability for its customers and revenue stability for the Company. As I will
22 discuss later in my testimony, this condition is not unique to Montana-Dakota and
23 is, in fact, quite commonplace in the gas distribution segment of the energy

industry.

Q. Do the Cost of Service Study ("COSS") results presented by the Company's witness, Ms. Tamie Aberle, provide guidance in establishing the appropriate rate structure within each rate class?

A. Yes. The classified costs, as allocated to each class of service within the Company's COSS, provide useful cost information in determining the level of customer, demand and commodity charges.

Q. Please explain how the classified costs from the Cost of Service Study presented by Ms. Aberle can be used for rate design purposes.

A. If the classified costs presented by Ms. Aberle in Statement N were used to set three-part rates (Customer, Demand and Commodity), the Company's operating expenses and return on investment in its non-gas revenue requirement would be fully recovered from its customers. The use of three part rates is becoming more widely accepted as the unbundling of utility services continues to evolve and the sale of the gas commodity in an increasingly competitive market is distinguishable from utility delivery service. The unit costs from the Company's COSS provide useful information for the design of portions of its tariff services, in particular for establishing cost-based fixed charges for customer related costs. The unit costs also can be used to design demand charges where either demand

metering is available or algorithm-based billing demands for its customers can be determined. Demand based rates provide for a unit charge based upon the maximum demand imposed by a customer on the utility's gas system within a specified time period, which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service.

Q. Please describe other considerations or criteria that should be used in the design of utility rates.

A. Utility rate design should recognize that rates must be just and reasonable and not cause undue discrimination. Thus, customer impact considerations must be factored into the rate design process. Market conditions within the utility service territory with respect to the general economic environment and competitive fuel prices, where appropriate, should be reviewed. Another important consideration is the financial stability of the utility. Toward this goal, it is generally an unsound ratemaking practice to recover a substantial portion of fixed costs, such as customer related costs which bear no relationship to customer consumption patterns, in the volumetric portion of the rate structure. Recovery of fixed costs via volumetric rates adversely impacts earnings stability because the revenues generated from customers' volumetric use of gas can be extremely sensitive to the vagaries of weather patterns and changing consumption characteristics. Moreover, recovery of utility fixed costs in volumetric rates sends uneconomic price signals to consumers that impede their ability to make well reasoned

energy consumption decisions. Ultimately, Montana-Dakota must establish a reasonable balance between the various cost guidelines and the other aforementioned criteria in the process of designing rates.

Q. Do the Company's proposed rate schedules reflect increases to its existing monthly service charges?

A. Yes. The Company's schedule of proposed rates includes an increase to the level of the existing residential monthly basic service charge from $7.00 to $12.77 for small meters (less than 500 cu. ft. per hour). As discussed by Ms. Aberle, the differential related to meter size in the basic service charge has been eliminated for the residential class. The current residential basic service charge for large meters is $14.00 per month. In addition, the proposed firm general service rate includes an increase in the monthly basic service charges from $7.50 to $27.36 for small meters (less than 500 cu. ft. per hour) and from $15.00 to $54.72 for large meters. The proposed basic service charges are stated on a daily basis, as explained by Ms. Aberle.

Q. Do increased fixed charges such as those proposed by the Company provide any benefits to customers?

A. Yes. An increase in the fixed charge component of the rate structure has the effect of reducing the impact of weather variances on customers' bills. By

increasing the basic service charge, the usage or volumetric charge is reduced, resulting in lower customer bills during periods of colder than normal weather and generally adding a measure of stability to the monthly bills of customers throughout the year.

Higher monthly basic service charges help equalize the contribution of each customer within a class towards recovery of the customer-related costs attributable to that class. The increase in the basic service charge will thus help reduce intra-class subsidies. When the basic service charge does not recover the fixed costs of serving a customer, the higher use customers subsidize the lower use customers.

Furthermore, the pricing practices associated with consumer services have evolved in recent years to be more oriented towards fixed charges, which have been widely embraced by the public. Today's consumer is much more accustomed to paying higher up-front fixed charges in exchange for low, or non-existent, usage charges. For example, basic cable television service carries a flat monthly charge and many internet service providers have restructured their pricing in the form of fixed monthly fees with no additional usage charges. Cellular phone companies offer a multitude of rate plans with an escalating scale of fixed monthly charges in exchange for additional "free" talk time. In addition, rental car companies typically charge a flat daily fee that permits the customer to drive, in some cases, an unlimited number of miles without incurring additional

usage charges. Finally, at the federal level, the FERC moved to a straight fixed-variable rate design for interstate pipelines with the issuance of Order No. 636.

Q. Why is the Company proposing to increase these service charge levels?

A. As mentioned earlier in my testimony, the Company utilized the unit costs from its cost of service study to identify costs related to providing monthly service to customers. The level of customer-related costs for its residential class of customers, as presented in Statement N, is $16.05 per month. The corresponding level of customer costs for the firm general class of customers, as presented in this exhibit, averages $39.29 per month over all meter sizes.

Establishing higher monthly basic service charges helps to reduce the intra-class subsidies that exist within a particular rate class. This method of customer cost recovery is preferable to including such costs in the commodity block charges, which has the effect of causing higher use customers to subsidize the lower use customers relative to the customer-related costs they impose on the Company.

The basic service charges provide for recovery of a portion of the Company's fixed customer costs that are incurred solely because of the existence of customers connected to its gas distribution system. These costs, associated with facilities in place to serve customers, regardless of use and expenses such as reading meters and billing, occur regardless of whether gas is consumed and are

not related to demands placed on the system. The proposed basic service charge increases will also ensure recovery by the Company of a greater portion of its fixed costs of providing service. Since customer costs are not related to gas usage, they should be recovered to the extent possible through a tariff component that does not depend upon volumetric billing.

Q. In view of the level of customer costs indicated by the Company's cost study, would you please explain the choice of the basic service charge levels that have been proposed?

A. Given the relatively high level of customer costs shown in Statement M as compared to its current level of customer related charges, the Company has chosen to move much closer to full cost of service in setting new customer related charges (basic service charge). In the case of the residential class, the current level of its customer-related fixed charge recovers only 44% of the level of customer costs identified in Montana-Dakota's cost of service study. The proposed basic service charge for the Company's Residential Gas Service (Rate 60) of $12.77 per month ($0.42/day) will address the current gap between this class' customer-related costs and its corresponding unit charge. The Company's proposed levels of basic service charges for the Firm General Gas Service (Rate 70) would bring this class within $263,330 or 89% of its full cost of service of $2,300,556.

1 **Q. At these proposed rate levels, would the Company's monthly basic service**
2 **charges result in substantial recovery of the fixed costs for these classes?**
3
4 A. Yes. However, there still exists approximately $1.7 million of remaining
5 customer-related costs and $2.9 million of fixed demand-related costs in the
6 residential and firm general service classes, representing approximately 38% of
7 the total fixed distribution costs of the Company, to be recovered through the
8 volumetric rates for the residential and firm general classes.
9
10 **Q. Are Montana-Dakota's efforts to improve its distribution margin recovery**
11 **through increased fixed cost recovery in its fixed monthly charges**
12 **consistent with the recent actions of other gas distribution companies?**
13
14 A. Yes. In my opinion, there has been a noticeable recent trend in the gas
15 distribution utility industry to increase monthly fixed charges. The monthly fixed
16 charges are often labeled as customer charges, base charges, or basic service
17 charges. Over the last few years, many gas distribution companies have
18 requested increases to their monthly customer charges, where feasible, based
19 on the results of cost of service studies that indicate gaps between the currently
20 approved customer charges and the corresponding levels of allocated customer
21 costs. As a result, customer charges have been increasing over time, and in
22 some cases, increasing on a disproportionate basis.
23

The results of a recent informal survey conducted by NCI of North American gas distribution companies confirm these conclusions. Forty-one (41) of the gas distribution companies surveyed had implemented increases to their monthly service charges since 1999. Of the sixty-four (64) companies surveyed, encompassing eighty-one (81) different state or provincial service territories, forty-three (43) respondents had residential monthly service charges greater than or equal to $9.00, with the average monthly service charge for this group equal to $10.67. The results of the NCI survey are presented in Exhibit No. ___ (RAF-1), Survey of Monthly Customer Charges of North American Gas Distribution Utilities.

Alternative Distribution Delivery Stabilization Mechanism

Q. Is the Company proposing a Distribution Delivery Stabilization Mechanism ("DDSM") to adjust rates to its heat sensitive classes of service to reflect the actual weather conditions it experiences on an annual basis in comparison to the normal weather it uses to establish base rates?

A. Yes. As presented earlier in my testimony, the Company's preference is to address variability in margin recovery through increased collection of fixed costs through fixed charges. However, an acceptable alternative rate design technique would be to increase monthly fixed charges by some level and implement a DDSM to correct for the over and under collection of distribution delivery

revenues, due to weather fluctuations, on an annual basis. The DDSM would apply to the Company's weather sensitive rate classes of residential and firm general service.

Q. Please discuss the reasons for recommending a DDSM.

A. Because of Montana-Dakota's largely volumetric rate design, as discussed earlier in my testimony, the Company will only recover its Commission authorized level of non-gas fixed costs of providing distribution service if the underlying sales volumes are achieved. Deviations from normal weather, the basis for those underlying sales volumes, result in either over or under recovery of Montana-Dakota's fixed costs. Erratic financial results from the constant over and under recovery of distribution margin can adversely impact Montana-Dakota's outlook in the financial community and, ultimately could increase the Company's financing costs. A DDSM addresses the foregoing adverse conditions. It is based on the premise that normal weather represents the best estimate of an uncontrollable variable and is a logical method for Montana-Dakota to adjust rates to account for the unpredictability of weather. A deferral type of DDSM would address wide swings in Montana-Dakota's total margin recovery through modest year-to-year adjustments in customers' bills in subsequent periods.

1 **Q. How does a deferral type of DDSM operate?**

2

3 A. A deferral type of adjustment mechanism is a simplified application of the
4 concepts used in the development of weather normalization mechanisms for
5 other gas utilities that corrects for the over/under collection of revenues due to
6 weather fluctuations throughout the winter heating season. Once a year,
7 following the end of the winter heating season, a true-up calculation would be
8 performed to compare actual weather conditions, as represented by the actual
9 level of annual Heating Degree Days (HDDs), with the level of HDDs under
10 normalized weather conditions. The Company would utilize the normal level of
11 HDDs established in the instant general rate case. The HDD excess or
12 deficiency for the winter period would be applied to the class-by-class use per
13 customer per HDD, also from the general rate case, and the respective class-by-
14 class delivery service margins. The resulting revenue excess or deficiency would
15 be divided by the projected annual sales volumes for the identified rate classes to
16 determine a surcharge or refund component to be applied as an adjustment to
17 the distribution charge.

18

19 **Q. Please provide a formulaic representation of the DDSM that you just**
20 **described.**

21

22 A. A formulaic representation of the DDSM is as follows:

23

$$DDSM_i = \frac{R_i\,(DDF_i\,(NDD - ADD)) + (PDDSM_i - ADDSM_i)}{ANU_i}$$

Where:

$DDSM_i$ = Distribution Delivery Stabilization dollar amount per dk

i = Applicable rate class subject to the DDSM

R_i = Applicable distribution delivery charge rate per dk

DDF_i = Temperature sensitive use per customer per degree day

NDD = Normal degree days for the winter service period

ADD = Actual degree days for the winter service period

ANU_i = Average normal use per customer for the prospective twelve month period

$PDDSM_i$ = Projected DDSM revenue from the preceding twelve month period

ADDSMi = Actual DDSM revenue recovered during the preceding twelve month period

The result of the calculation, the DDSM factor, is multiplied by the customer's monthly gas consumption and added to or subtracted from the customer's bills during the twelve-month recovery/refund period, depending on the arithmetic sign of the DDSM.

Q. Can this type of DDSM accommodate any variation in the actual margin revenues collected through the DDSM in a particular year compared to the expected level of margin revenues upon which the previous DDSM factor was derived?

A. Yes, it can. The illustrated DDSM has a true-up feature that will adjust the DDSM factor in any subsequent year to reflect any over-collections or under-collections in the prior year caused by variations in the margin revenues derived through application of the then current DDSM factor to the Company's actual gas volumes.

Q. Have you tested the performance of a deferral type of DDSM on Montana-Dakota's recent experience with weather variability in its Wyoming service territory?

A. Yes. Exhibit No.___(RAF-2), DDSM Analysis, provides an illustration of the operation of the annual adjustment mechanism and the determination of the DDSM. Revenue adjustments were computed that would have occurred had this

type of DDSM been in effect during each of the last four complete heating seasons, from 1997 – 1998 to 2001 – 2002.

Q. Why was this time period selected to demonstrate the operation of the DDSM?

A. This time period was chosen because it contained weather extremes, both above and below normal conditions assumed by the Company.

Q. Please describe the results of your analysis.

A. The results of the analysis are shown on Exhibit No.___(RAF-2). This schedule shows the year-to-year impact on the Company's revenues due to the variations in temperature. A negative adjustment of ($284,379) would have occurred at the end of the 2000 – 2001 heating season, due to the 8.9% colder than normal temperatures. By contrast, a positive adjustment of $724,513 would have occurred at the conclusion of the 1999 – 2000 heating season resulting from 21.9% warmer than normal temperature conditions.

Q. Have you analyzed how this DDSM would have impacted individual customer bills?

A. Yes. The average annual impact on individual residential customer bills

1 corresponding to the 2000 – 2001 colder than normal heating season would have
2 been a negative adjustment of ($4.82). Likewise, a positive total adjustment to
3 an average residential customer bill of $11.95 would have resulted from the 1999
4 – 2000 warmer than normal heating season. The annual customer DDSM
5 adjustments are shown in the analysis for the heat sensitive classes. In view of
6 the temperature variations that occurred during the heating seasons examined,
7 the analysis presented in Exhibit No. __ (RAF – 2) confirms what one would
8 expect to result from the operation of the DDSM, had it been in effect during
9 those years.
10
11 **Q. Mr. Feingold, does that complete your direct testimony?**
12
13 A. Yes, it does.

RUSSELL A. FEINGOLD

EDUCATION

- Bachelor of Science degree in Electrical Engineering from Washington University, St. Louis.
- Master of Science degree in Financial Management from Polytechnic Institute of New York

PROFESSIONAL EMPLOYMENT

1997 – Present	**Navigant Consulting, Inc.** Managing Director, Regulation & Litigation Support Practice
1990 – 1997	**R.J. Rudden Associates, Inc.** Vice President and Director
1985 – 1990	**Price Waterhouse** Director, Gas Regulatory Services Public Utilities Industry Services Group
1978 – 1985	**Stone & Webster Management Consultants, Inc.** Executive Consultant Regulatory Services Division
1973 – 1978	**Port Authority of New York and New Jersey** Staff Engineer and Utility Rate Specialist Design Engineering Division

PRESENTATION OF EXPERT TESTIMONY

- Federal Energy Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Montana Public Service Commission
- New Hampshire Public Utilities Commission
- New Jersey Board of Public Utilities
- New York Public Service Commission
- North Dakota Public Service Commission
- Ohio Public Utilities Commission
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Quebec Natural Gas Board (Canada)
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission

- Public Service Commission of Wyoming

EDUCATIONAL AND TRAINING ACTIVITIES

- Chairman, Rate Training Subcommittee, Rate and Strategic Issues Committee of the American Gas Association
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- Course organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison, 1985 – 2002
- Course organizer and speaker at the annual industry course, American Gas Association – Advanced Regulatory Seminar, University of Maryland - College Park, 1987 –1992
- Co-founder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987
- Contributing Author of the Fourth Edition of "Gas Rate Fundamentals," American Gas Association, 1987
- Organizer, Editor, and Contributing Author of the upcoming Fifth Edition of "Gas Rate Fundamentals," American Gas Association (in progress)

PUBLICATIONS AND PRESENTATIONS

- "Unbundling Initiatives – How Far Can We Go?" American Gas Association Restructuring Seminar: Service and Revenue Enhancements for the Energy Distribution Business, December 2002.
- "Utility Regulation and Performance-Based Ratemaking (PBR)," PBR Briefing Session sponsored by BC Gas Utility Ltd., April 2002.

- "LDC Perspectives on Managing Price Volatility" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2002.
- "Can a California Energy Crisis Occur Elsewhere?" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2001.
- "Downstream Unbundling: Opportunities and Risks," American Gas Association, Rate and Strategic Issues Committee Meeting, April 2000.
- "Form Follows Function: Which Corporate Strategy Will Predominate in the New Millennium?" American Gas Association 1999 Workshop on Regulation and Business Strategy for Utilities in the New Millennium, August 1999
- "Total Energy Providers: Key Structural and Regulatory Issues," American Gas Association, Rate and Strategic Issues Committee Meeting, April 1999.
- "The Gas Industry: A View of the Next Decade," National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Accounts, 1998 Fall Meeting, September 1998.
- "Regulatory Responses to the Changing Gas Industry," Canadian Gas Association, 1998 Corporate Challenges Conference, September 1998
- "Trends in Performance-Based Pricing," American Gas Association Financial Analysts Conference, May 1998.
- "Unbundling – An Opportunity or Threat for Customer Care?" presented at the American Gas Association/Edison Electric Institute Customer Services Conference and Exposition, May 1998.
- "Experiences in Electric and Gas Unbundling," presented at the 1997 Indiana Energy Conference, December 1997.
- "Asset and Resource Migration Strategies," presented at the Strategic Marketing For The New Marketplace Conference sponsored by Electric Utility Consultants, Inc. and Metzler & Associates, November 1997.
- "The Status of Unbundling in the Gas Industry," presented at the American Gas Association Finance Committee, March 1997.

- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- "State Regulatory Update," presented at the American Gas Association - Financial Forum, May 1995.
- "Gas Pricing Strategies and Related Rate Considerations," presented before the Rate Committee of the American Gas Association, April 1995.
- "Avoided Cost Concepts and Management Considerations," presented before the Workshop on Avoided Costs in a Post-636 Industry, sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, June 1994.
- "DSM Program Selection Under Order No. 636: Effect of Changing Gas Avoided Costs," presented before the NARUC-DOE Fifth National Integrated Resource Planning Conference, Kalispell, MT, May 1994.
- "A Review of Recent Gas IRP Activities," presented before the Rate Committee of the American Gas Association, March 1994.
- Seminar organizer and co-moderator at the American Gas Association seminar, "The Statue of Integrated Resource Planning," December 1993.
- "Industry Restructuring Issues for LDCs, presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland, 1993-1996.
- "Acquiring and Using Gas Storage Services," presented before the 8th Cogeneration and Independent Power Congress and Natural Gas Purchasing '93, June 1993.
- "Capitalizing on the New Relationships Arising Between the Various Industry Segments: Understanding How You Can Play in Today's Market," presented before the Institute of Gas Technology's Natural Gas Markets and Marketing Conference, February 1993.
- "The Level Playing Field for Fuel Substitution (or, the Quest for the Holy Grail)," presented before the 4th Natural Gas Industry Forum - Integrated Resource Planning: The Contribution of Natural Gas, October 1992.

- "Key Methodological Considerations in Developing Gas Long-Run Avoided Costs," presented before the NARUC-DOE Fourth National Integrated Resource Planning Conference, September 1992.
- "Mega-NOPR Impacts on Transportation Arrangements for IPPs," co-presented before the 7th Cogeneration and Independent Power Congress and Natural Gas Purchasing '92, June 1992.
- "Cost Allocation in Utility Rate Proceedings," presented before the Ohio State Bar Association - Annual Convention, May 1992.
- "The Long and the Short of LRACs," presented before the Natural Gas Least-Cost Planning Conference April 1992, sponsored by Washington Gas Company and the District of Columbia Energy office.
- Seminar organizer and moderator at the American Gas Association seminar, "Integrated Resource Planning: A Primer," December 1991.
- Session organizer and moderator on integrated resource planning issues at the American Gas Association Annual Conference, October 1991.
- "Strategic Perspectives on the Rate Design Process," presented before the Executive Enterprises, Inc. conference, "Natural Gas Pricing and Rate Design in the 1990s," September 1990.
- "Distribution Company Transportation Rates," presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland 1987-1992.
- "Design of Distribution Company Gas Rates," presented before the American Gas Association - Gas Rate Fundamentals Course, University of Wisconsin, 1985-1998.
- Seminar organizer, speaker and panel moderator at the American Gas Association seminar, "Natural Gas Strategies: Integrating Supply Planning, Marketing and Pricing," 1988-1990.
- "Local Distribution Company Bypass - Issues and Industry Responses," (Co-author) June 1989.

- "So You Think You Know Your Customers!," presented before the American Gas Association–Annual Marketing Conference, April 1990.
- "Gas Transportation Rate Considerations - A Review of Gas Transportation Practices Based on the Results of the A.G.A. Annual Pricing Strategies Survey," presented before the Rate Committee of the American Gas Association, April 1985-1991.
- "Market-Based Pricing Strategies - Targeted Rates to Meet Competition," presented before the American Gas Association Annual Marketing Conference, March 1989.
- "Gas Rate Restructuring Issues - Targeted Prices to Meet Competition," presented before the Fifteenth Annual Rate Symposium, University of Missouri, February 1989.
- "Gas Transportation Rates - An Integral Part of a Competitive Marketplace," *American Gas Association, Financial Quarterly Review*, Summer 1987.
- "Gas Distributor Rate Design Responses to the Competitive Fuel Situation," *American Gas Association, Financial Quarterly Review*, October 1983.
- "Demand-Commodity Rates: A Second Best Response to the Competitive Fuel Situation," presented before the American Gas Association, Ratemaking Options Forum, September 1983.
- Cofounder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.
- "Current Rate and Regulatory Issues," presented before the National Fuel Gas Regulatory Seminar, July 1986.

AFFILIATIONS AND HONORS

- Financial Associate Member, American Gas Association
- Member, Rate and Strategic Issues Committee of the American Gas Association
- Member, Energy Bar Association

- Member, Institute of Electrical and Electronic Engineers
- Listed in Who's Who of Emerging Leaders in America, 1989-1992

(Current as of December 2002)

Montana-Dakota Utilities Company
Survey of Monthly Customer Charges
of North American Gas Distribution Utilities

	Company		Current Customer Charge	Current Charge Effective		Company		Current Customer Charge	Current Charge Effective
	(A)		(B)	(C)		(D)		(E)	(F)
1	Ameren (IL)		$ 9.50	Feb-99	42	MidAm (IL)		$ 9.00	Jul-00
2	Ameren (MO)		$ 9.00	Nov-00	43	Missouri Gas		$ 10.05	Aug-01
3	Apollo Gas (PA)		$ 9.00	N/A	44	Nashville Gas Division		$ 8.00	Dec-00
4	Arkansas Oklahoma Gas		$ 9.00	Sep-97	45	New Jersey Natural Gas Co.		$ 6.54	Dec-00
5	ArkLa (TX)		$ 10.70	N/A	46	NFG (NY)		$ 14.18	Oct-97
6	ATCO Gas North		$ 7.68	Jan-01	47	NFG (PA)		$ 11.09	May-93
7	ATCO Gas South		$ 8.41	Jan-01	48	Niagara Mohawk		$ 14.55	Aug-00
8	Atlanta Gas Light		$ 9.76	N/A	49	NIPSCO		$ 6.36	Dec-00
9	Atlas Gas Utilities		$ 9.06	Jan-01	50	Northern Utilities (ME)		$ 9.92	N/A
10	Avista Utilities		$ 5.00	Dec-00	51	Northern Utilities Natural (NH)		$ 6.91	Dec-00
11	Baltimore Gas & Electric		$ 12.25	Jun-00	52	Northwest Natural (Rate 2) (WA)		$ 4.00	Nov-00
12	Bay Stae Gas (MA)		$ 7.47	Dec-00	53	Northwest Natural (Rate 24) (WA)		$ 4.00	Nov-00
13	Berkshire Gas (MA)		$ 10.50	Feb-02	54	Northwest Natural (OR)		$ 5.00	Dec-00
14	Boerne Utilities (TX)		$ 11.00	N/A	55	NYSEG (NY)		$ 14.00	N/A
15	Boston Gas Company		$ 9.98	N/A	56	Ohio Valley (OH)		$ 11.19	Nov-95
16	Centra Gas, (MB)		$ 6.47	Nov-00	57	Peoples Gas (Non-West Fla Region)		$ 7.00	Nov-00
17	Central IL Pub. Serv.		$ 9.50	Feb-99	58	PG Energy (PA)		$ 11.25	Jan-01
18	Central Ill Light & Power		$ 9.85	Jun-97	59	PNG- West (BC)		$ 6.95	Jan-01
19	Cheyenne Light, Fuel & Power		$ 9.00	Aug-00	60	PNG (NE) Ltd. (Dawson Creek)		$ 4.53	Jan-01
20	CILCO (IL)		$ 9.85	N/A	61	PNG (NE) Ltd. (Tumbler Ridge)		$ 5.50	Jan-01
21	Citizens Gas & Coke Utility (IN)		$ 9.00	N/A	62	Providence Gas Company		$ 8.00	Jan-96
22	Columbia Gas (MD)		$ 9.25	Apr-00	63	Public Service Co (NM)		$ 9.00	Oct-00
23	Columbia Gas (PN)		$ 10.81	Oct-00	64	Puget Sound		$ 4.46	Jan-01
24	Columbia Gas (PA)		$ 11.35	N/A	65	Reliant Energy (MS)		$ 9.30	N/A
25	Columbia Gas (VA)		$ 12.25	N/A	66	SaskEnergy, SK (Farm)		$ 7.47	Dec-00
26	Con Ed (NY)		$ 11.82	Dec-98	67	SaskEnergy, SK (Residential)		$ 6.79	Dec-00
27	Consumers Energy Co. (MI)		$ 6.50	Mar-00	68	South Carolina Elect & Gas		$ 3.00	Nov-00
28	Delta Natural Gas Co. (KY)		$ 8.00	Nov-00	69	Southern California Gas		$ 10.00	Dec-98
29	Dominion Peoples (PA)		$ 11.00	Mar-00	70	Southwest Gas Corp. (North)		$ 6.00	Jan-01
30	Enbridege Consumers (On)		$ 6.47	Oct-00	71	Southwest Gas Corp. (South)		$ 6.00	Jan-01
31	Equitable (PA)		$ 11.65	Oct-97	72	UGI (PA)		$ 8.55	Aug-95
32	Gaz Metropolitain (PQ)	[1]	$ 6.03	Oct-99	73	Union Gas (ON) (Eastern)		$ 6.47	Oct-00
33	Illinois Gas		$ 9.55	Oct-98	74	Union Gas (ON) (Fort Frances)		$ 5.82	Oct-00
34	Illinois Power		$ 9.95	Jan-94	75	Union Gas (ON) (Northern)		$ 6.47	Oct-00
35	Indiana Gas		$ 9.00	N/A	76	Union Gas (ON) (S. Western)		$ 4.85	Oct-00
36	Intermountain Gas (Apr-Nov)	[2]	$ 2.50	Dec-00	77	Union Gas (ON) (Western)		$ 6.47	Oct-00
37	Intermountain Gas (Dec-Mar)	[2]	$ 6.50	Dec-00	78	United Cities (IL)		$ 9.90	Oct-00
38	KeySpan Energy (NH)		$ 7.89	Dec-00	79	United Cities (VA)		$ 6.00	Mar-01
39	Keyspan (NY)		$ 21.16	Oct-01	80	VA Natural Gas		$ 9.78	N/A
40	Laclede Gas (MO)		$ 12.00	Sep-96	81	Valley Gas Company (RI)		$ 5.60	Jan-95
41	MidAm (IA)		$ 9.00	May-99	82	Yankee Gas (CT)		$ 8.75	N/A

[1] Charge stated as a daily charge of 0.19832. For the purpose of this exhibit it has been multiplied by 30.4 (average number of days in a month)
[2] Charges are seasonally differentiated and apply to the same jurisdiction.

Customer Charge Statistics

Mean	$ 8.58
Median	$ 9.00
Mode	$ 9.00
Range	$ 18.66
Minimum	$ 2.50
Maximum	$ 21.16
Count	82

Average of Charges Greater than or Equal to $9.00 = $ 10.67

Montana-Dakota Utilities Co.
Distribution Delivery Stabilization Mechanism Analysis
Gas Utility - South Dakota

	Heating Use			Firm	Total	Total Firm	Adjustment
	Actual	Normal	Residential	General	DDSM	Sales [1]	Per Dk
1997	3,295,015	3,413,881	$92,670	$40,055	$132,725	4,983,259	$0.027
1998	3,146,296	3,452,558	243,268	100,171	343,439	5,225,797	$0.066
1999	2,972,228	3,618,280	513,275	211,238	724,513	5,228,388	$0.139
2000	3,758,979	3,504,247	(198,427)	(85,952)	(284,379)	5,046,169	($0.056)
2001	3,301,280	3,584,285	228,405	90,135	318,540	5,196,216	$0.061
Average Adjustment					$1,234,838	25,679,829	$0.048

Customer Bill Impact of DDSM:

		Residential	Firm General	Firm General
		Small Meter	Small Meter	Large Meter
	Annual Usage (Dk)	86	300	1,225
1997	**Annual Impact**	$2.32	$8.10	$33.08
1998		$5.68	$19.80	$80.85
1999		$11.95	$41.70	$170.28
2000		($4.82)	($16.80)	($68.60)
2001		$5.25	$18.30	$74.73
Average Adjustment		$4.13	$14.40	$58.80

[1] Adjustment is based on subsequent year's normalized sales.

Docket No. ____
Exhibit No. ____ (RAF-2)
Page 1 of 1

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

Before the Public Utilities Commission of South Dakota

Docket No. NG02-___

Direct Testimony
of
Tamie A. Aberle

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

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

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

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

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

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

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

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

1 my present position in May 1999.

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

3 A. Yes. I have previously filed testimony with this Commission and
4 the Minnesota Public Utilities Commission, and presented testimony
5 before the Montana Public Service Commission, North Dakota Public
6 Service Commission and the Wyoming Public Service Commission.

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

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

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

16 A. I am sponsoring Rule 20:10:13:97 Statement N, Rule 20:10:13:98
17 Statement O and Exhibit No. ____ (TAA-1) through Exhibit No. ____
18 (TAA-3).

19 Q. Do you also sponsor the proposed rate schedules appended to the
20 Application in this proceeding?

21 A. Yes, I do.

22 Q. Do the proposed changes affect the customers served in the East River
23 service territory?

24 A. No they do not. Rate Schedules 66 and 89 applicable to the
25 customers located in the East River System have been updated to reflect
26 the new tariff form but the charges remain the same as currently

1 authorized.

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

3 A. The proposed rates will produce additional revenues of $2,173,380
4 or 5.8% annually based on projected throughput. Exhibit No. ____ (TAA-
5 1) represents summaries by rate classification of the proposed revenue
6 increase for the projected 2003 test year and is identical to Statement O,
7 Page 1. The exhibit shows the rate number and a description along with
8 the revenues calculated under the present and proposed rates for the
9 projected 2003 test year. The amount and percentage increase is also
10 shown for the proposed revenue increase.

11 Q. Would you please explain the embedded class cost of service study
12 contained in Statement N?

13 A. Yes. Turning to Part A, the first report appearing therein is entitled
14 "Cost of Service by Component." This report shows the total dollars and
15 unit cost required under each rate if the overall requested 10.303% rate of
16 return was to be earned for the demand, energy and customer cost
17 components of each rate schedule.

18 The next report appearing in Statement N is entitled "Summary."
19 This report shows the results of all of the succeeding reports in summary
20 form. Following this summary report is a detailed report showing the
21 development of each line on the Summary Report.

22 Part B of Statement N, entitled "Allocation Assignment Report," is a
23 report that shows how the various allocation factors and items directly
24 assigned were applied in producing the various reports shown in Part A.

25 Part C of Statement N, entitled "Allocation Factor Report," is simply
26 a list of the allocation factors used to produce the various reports shown in

1 Part A. By using the Allocation Assignment Report and the Allocation
2 Factor Report, it can be readily determined how the various components
3 of revenue, expense, and plant were allocated or assigned among the
4 classes of service.
5 The class cost of service study is based on the results for South
6 Dakota gas operations as recorded for the 12 months ended June 30,
7 2002 as adjusted to reflect the Projected 2003 test period underlying the
8 total cost of service in this case.
9 Q. What were the results of the cost of service study?
10 A. The results are summarized on Statement N, Part A, page 4.
11 The overall South Dakota gas rate of return based on the projected 2003
12 overall cost of service is 2.381%. The returns by customer class are as
13 shown below:

14 Residential Service	2.073%
15 Firm General Service	-1.376%
16 Air Force	65.914%
17 Small Interruptible	25.454%
18 Large Interruptible	33.399%

19 Q. For what purpose has the class cost of service study been used?
20 A. The study results have been used as a guide in the distribution of
21 total revenue requirements among customers and for the purpose of
22 pricing the various components comprising the total rate applicable to
23 each customer class.
24 Q. What methodology did you use to apportion the proposed rate increase
25 among the customer classes?
26 A. In designing the proposed rates to reflect the additional revenue

requirements, we have attempted to group the class rates of return more closely about the overall system return.

Given the disparity between the firm and interruptible class contributions to the overall return, the proposed increase was allocated by first increasing the Firm General Service class by an amount that brings the class to the overall rate of return of 10.303% and allocating the remaining increase to the Residential class.

Q. What is the percentage of the proposed final increase by class of customer?

A. As shown on Exhibit No. ____ (TAA-1), the proposed increase to each of the classes is as follows:

Class	% Increase
Residential	5.8%
Firm General Service	8.4%
Firm Contract Service	---
Air Force	---
Small Interruptible	---
Large Interruptible	---
Overall	**5.8%**

Q. Why did you not propose a change for the Firm Contract, Air Force or Interruptible customer classes?

A. An increase was not warranted as the noted classes are currently producing a return on investment in excess of the overall rate of return. A decrease was not proposed in order to mitigate the increase required from the residential and firm general service classes of customers.

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

A. The revenue allocation explained above results in an increase in the residential class return from 2.07% to 8.68% and an increase in the firm general service class return from –1.38% to 10.29%. The class returns for the Air Force and Interruptible classes remain unchanged from the projected 2003 level because no change in revenues is proposed for those classes.

Q. What changes are you proposing to the rate form applicable to the firm service customers?

A. In order to accomplish the rate structure objectives which include providing a measure of stability for our customers during periods of abnormal weather, having easily understandable rates for customers, having a rate form that is simple to administer and enhancing fixed cost recovery, the Company is proposing several changes to the firm service rate form. Our goal is to provide customers with price stability, better price signals and better information that will allow them to understand the nature of their gas bill. We propose to accomplish this by redefining the components of the gas bill applicable to all customers into 3 parts:

1. Basic Service Charge
2. Distribution Delivery Charge and
3. Cost of Gas

I will explain each component more fully below, including the changes that will accomplish the objectives noted above.

1. The <u>Basic Service Charge</u> applicable to each customer class has been moved closer to the customer cost level identified in the Class Cost of Service Study for each of the customer classes. This component is currently identified as the "base

rate" on the current tariffs. Setting the Basic Service Charge at or nearly at the customer cost level from the class cost of service study will serve to stabilize the portion of the bill currently recovered on a volumetric basis. The Basic Service Charges applicable to the Residential and Firm General Service classes have been stated on a daily basis. Charging this fixed cost on a daily basis better matches the way customers are billed i.e., the days between billing periods vary due to meter reading cycles and customer cut-ins and cut-outs occurring outside their normal billing cycle. Bills for service outside a normal period are currently normalized but the customer cannot readily determine how the bill was determined. A daily Basic Service Charge will allow the customer to simply multiply the number of days in service during the current billing period (now shown on the bill) times the applicable Basic Service Charge.

2. The Distribution Delivery Charge is proposed to be recovered through a flat commodity charge and the declining block rate currently applicable to Residential and Firm General Service customers under Rates 60, 70 and 72 will be eliminated. The declining block commodity rate is no longer required because the fixed customer related costs that are now recovered through the rate differential assigned to the 1st block of energy (1st 10 dk for residential customers and 1st 15 dk for firm general service customers) will now be properly recovered through the Basic Service Charge. The Distribution Delivery Charge primarily reflects the distribution demand related (fixed) costs discussed

by Mr. Feingold plus any customer related costs not recovered through the Basic Service Charge due to the rate design process.

3. The Cost of Gas component is comprised of the items currently recovered through the Purchased Gas Cost Adjustment Rate 88. Under the current rate form, the base cost of gas authorized in the last rate case is buried in the commodity charge component and the changes in gas cost related items are identified separately in a Purchased Gas Cost Adjustment. Under the proposed rate form customers will readily know what portion of their bill is associated with gas related costs that change upward and downward with the market price of natural gas changes and are subject to the Purchased Gas Cost Adjustment mechanism and not determined in a rate case proceeding such as this.

Q. What are you proposing as Basic Service Charges for the Residential and Firm General Service classes?

A. The Basic Service Charge proposed for customers taking service under Residential Rate 60 has been set at $0.42 per day, which reflects an average monthly charge of $12.77. The differential between meters rated less than 500 cubic feet per hour and those rated over 500 cubic feet per hour has been eliminated for the Residential class due to the small number of meters falling into the latter category. The differential has been retained for the Firm General Service Rate 70 rate schedule due to the diversity of customers served under this rate. The Basic Service Charge applicable to Firm General Service customers with meters rated

1 less than 500 cubic feet per hour has been set at $0.90 per day and $1.80
2 per day for customers requiring the larger meters capable of measuring
3 gas flows of 500 cubic feet per hour or greater. The resulting average
4 monthly charge will be $27.36 and $54.72 respectively.
5 Q. Would you please explain Exhibit No. ____(TAA-2)?
6 A. Yes. Exhibit No. ____ (TAA-2) depicts bill comparisons based on
7 typical monthly consumption levels for an annual period for residential and
8 firm general service customers. As shown by the comparisons, the
9 proposed rate structure will result in an average increase of approximately
10 $2.50 per month for the typical Residential customer using 86 dk on an
11 annual basis. The proposed rate form will also provide customers with
12 price stability during those months where their gas usage may vary
13 significantly due to the weather. For example, a residential customer
14 typically uses 15 dk during the month of January. Under the current rate
15 structure the customer's monthly bill will be $80.09 (based on gas costs
16 as of December 2002). Under the proposed rate structure the customer's
17 bill will be $80.60 – essentially the same amount. Properly recognizing
18 the fixed costs in a fixed charge minimizes the over-collection of customer
19 related costs by the Company in periods of colder than normal weather as
20 well as minimizing the under-collection during periods of warmer than
21 normal weather.
22 Q. What changes are you proposing to make to the optional seasonal rate
23 available to firm general service customers?
24 A. The Optional Seasonal General Gas Service Rate has been
25 revised to reflect the proposed Basic Service Charge and Distribution
26 Delivery Charge for Firm General Service Rate 70. The differential

1 between the summer and winter periods continues to be based on the
2 demand component of the cost of gas.
3 Q. What changes are you proposing to make to the Air Force Rate 64?
4 A. The Air Force Rate 64 has been revised to reflect an increase in
5 the Basic Service Charge from $95.00 per month to $250.00 per month.
6 The commodity charge has been calculated to produce the remaining
7 class revenue requirement. As noted earlier, no overall increase or
8 decrease is proposed for the Air Force.
9 Q. Would you please describe the changes proposed to the Small
10 Interruptible Service Rate 71 and Large Interruptible Service Rate 85
11 sales rates?
12 A. Yes. A Basic Service Charge of $175.00 per month has been
13 proposed for the small interruptible class (interruptible customers using
14 less than 40,000 dk annually) and a Basic Service Charge of $300.00 per
15 month is proposed for the large interruptible customer group (customers
16 using 40,000 dk or more annually). The proposed Basic Service Charges
17 reflect the customer costs determined in the embedded class cost of
18 service study while the interruptible commodity charges were calculated
19 as a residual to achieve each class' revenue requirement.
20 Q. Ms. Aberle, are you proposing any changes to the current interruptible
21 transportation service rates?
22 A. The only change to the interruptible transportation rates is an
23 increase in the Basic Service Charges to the level identified in the class
24 cost of service study. The current fee of $50.00 per month presently
25 identified as a nomination charge has been included with the Basic
26 Service Charge applicable to transportation service customers.

1 Q. Have you prepared a Distribution Delivery Stabilization Mechanism tariff
2 as an alternative as described by Mr. Fox and Mr. Feingold?
3 A. Yes. A Distribution Delivery Stabilization Mechanism (DDSM)
4 tariff, as discussed by Mr. Feingold, is depicted in Exhibit No. ____(TAA-
5 3). This mechanism, coupled with some level of increase in fixed monthly
6 charges, could be used as an alternative to the implementation of a Basic
7 Service Charge at the customer related cost level identified in the class
8 cost of service study which is the Company's primary proposal. As
9 described in the tariff, the DDSM would be applied to the firm service
10 classes as a per dekatherm adjustment reflecting the amortization of a
11 balancing account representing the over/under recoveries of the
12 Distribution Delivery Charge due to weather related volume fluctuations.
13 As noted by Mr. Fox and Mr. Feingold, if the Basic Service Charges
14 proposed are not adopted, the Company is requesting approval to adopt
15 the DDSM mechanism.
16 Q. Would you please briefly describe other changes made to the Company's
17 gas tariff?
18 A. Yes, following is a description of other changes the Company is
19 proposing to make to its gas tariff:
20 • A Rate Summary Sheet has been added to Section 3 of the
21 tariff to allow readers to see, at a glance, all charges associated
22 with a particular rate.
23 • The penalty for failure to curtail or interrupt, applicable under
24 each of the interruptible sales and transportation service
25 schedules has been increased from $10.00 per dk to $50.00
26 per dk in order to sensitize the critical nature of a call for

interruption and to provide sufficient incentive for a customer to interrupt or curtail their use of gas when called upon to do so.

- A provision requiring interruptible customers to notify the Company of a significant change in daily operations and the requirement to provide a power supply and phone service to electronic meter equipment deemed necessary by the Company has been added to both interruptible sales schedules (Rate 71 and Rate 85). The requirements are necessary to properly manage gas supplies for the interruptible sales customers and to minimize the potential for penalties assessed by the interconnecting pipelines.
- Firm Gas Transportation Service Rate 84, currently available for the firm requirements of interruptible customers, has been eliminated due to lack of customer interest in this rate option.
- The fee charged when a check is returned for non-payment back to the Company has been increased to $20.00 to reflect the current going rate charged by banks and other businesses.
- The reconnection fees for seasonal customers will now be tied to the Basic Service Charge that would have been applied during the period the customer was out of service with a minimum set at the actual cost associated with reconnecting the service. The reconnection charge for a customer disconnected for nonpayment of bills has been increased to $30.00, the actual cost of reconnecting service.
- A section describing the Company's policy regarding unauthorized use of service has been added to General

1 Provisions Rate 100.

2 • The deposits associated with a gas meter test requested by a
3 customer (Rate 100, Paragraph 22) have been revised to reflect
4 current costs.

5 • Firm Gas Service Extension Policy Rate 120 and Rate 124
6 related to service line installations have been revised to reflect
7 the Company's proposal to own all prospective service line
8 installations as discussed by Mr. Fox and Ms. Mulkern in their
9 testimony. The Company is proposing to install service lines
10 that are cost justified by the expected connected load at no cost
11 to the customer. A customer contribution will be required for
12 the portion of the installation not supported by the expected
13 connected load in accordance with the Maximum Allowable
14 Investment formula currently used under Firm Gas Service
15 Extension Policy Rate 120. The change in service line policy
16 has allowed the elimination of Rate 125, which was applicable
17 to company-owned service lines within the Company's East
18 River service territory.

19 • The forms included in Section No. 6 have been updated to
20 reflect the Company's current set of forms.

21 • Minor changes, which are self-explanatory, have been made to
22 the majority of the rate schedules. These changes are clearly
23 denoted on the tariff sheets reflecting the legislative format.

24 Q. Does this conclude your direct testimony?

25 A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - SOUTH DAKOTA

Customer Class/Rate	Projected 2003 Customers 1/	Projected 2003 Dk	Projected 2003 Revenue 2/	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	35,841	3,151,151	$20,560,052	$21,761,669	$1,201,617	5.8%
Firm General Service - Rate 70 & 72	4,880	2,151,036	11,621,009	12,592,360	971,351	8.4%
Firm Contract Service Rate	1	625,741	2,441,189	2,441,189	0	0.0%
Air Force Service - Rate 64	1	569,719	1,753,026	1,753,176	150	0.0%
Small Interruptible						
Sales - Rate 71	12	38,760	188,950			
Transport - Rate 81	33	364,450	205,543			
Total Small Interruptible	45	403,210	394,493	394,675	182	0.0%
Large Interruptible						
Sales - Rate 85	1	83,120	269,779			
Transport - Rate 82	13	664,670	147,046			
	14	747,790	416,825	416,905	80	0.0%
Total South Dakota	40,782	7,648,647	$37,186,594	$39,359,974	$2,173,380	5.8%

1/ Bills divided by 12.
2/ Rates effective as of December 1, 2002.

Docket No. ____
Exhibit No. ____ (TAA-1)
Page 1 of 1

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE (SMALL METERS)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	15	$80.09	$80.60	$0.51	0.64%
February	11	61.93	62.51	0.58	0.94%
March	11	61.93	62.51	0.58	0.94%
April	7	42.27	44.42	2.15	5.09%
May	4	27.16	30.86	3.70	13.62%
June	3	22.12	26.34	4.22	19.08%
July	2	17.08	21.81	4.73	27.69%
August	2	17.08	21.81	4.73	27.69%
September	3	22.12	26.34	4.22	19.08%
October	6	37.23	39.90	2.67	7.17%
November	9	52.35	53.47	1.12	2.14%
December	13	71.01	71.56	0.55	0.77%
Total	86	$512.37	$542.13	$29.76	5.81%

PRESENT RATE 60: 1/		PROPOSED RATE 60: 2/	
Base Rate	$7.00	Basic Delivery Charge	$12.77
1st 10 dk	$5.039	Distribution Delivery	$0.890
Over 10 dk	4.539	Cost of Gas	$3.632

1/ Rate effective December 1, 2002.
2/ Includes December 2002 Cost of Gas based on .86% loss factor plus surcharge.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE (LARGE METERS)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	82	$391.20	$383.57	($7.63)	-1.95%
February	63	304.96	297.66	(7.30)	-2.39%
March	63	304.96	297.66	(7.30)	-2.39%
April	39	196.02	189.13	(6.89)	-3.51%
May	24	127.94	121.30	(6.64)	-5.19%
June	15	87.09	80.60	(6.49)	-7.45%
July	10	64.39	57.99	(6.40)	-9.94%
August	10	64.39	57.99	(6.40)	-9.94%
September	19	105.24	98.69	(6.55)	-6.22%
October	34	173.33	166.52	(6.81)	-3.93%
November	53	259.57	252.44	(7.13)	-2.75%
December	73	350.35	342.88	(7.47)	-2.13%
Total	485	$2,429.44	$2,346.43	($83.01)	-3.42%

PRESENT RATE 60: 1/		PROPOSED RATE 60: 2/	
Base Rate	$14.00	Basic Delivery Charge	$12.77
1st 10 dk	$5.039	Distribution Delivery	$0.890
Over 10 dk	$4.539	Cost of Gas	$3.632

1/ Rate effective December 1, 2002.
2/ Includes December 2002 Cost of Gas based on .86% loss factor plus surcharge.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE (SMALL METERS)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	51	$239.33	$244.93	$5.60	2.34%
February	39	186.55	193.73	7.18	3.85%
March	39	186.55	193.73	7.18	3.85%
April	24	120.56	129.74	9.18	7.61%
May	15	80.97	91.35	10.38	12.82%
June	9	51.58	65.75	14.17	27.47%
July	6	36.89	52.96	16.07	43.56%
August	6	36.89	52.96	16.07	43.56%
September	12	66.28	78.55	12.27	18.51%
October	21	107.36	116.95	9.59	8.93%
November	33	160.15	168.14	7.99	4.99%
December	45	212.94	219.33	6.39	3.00%
Total	300	$1,486.05	$1,608.12	$122.07	8.21%

PRESENT RATE 70: 1/		PROPOSED RATE 70: 2/	
Base Rate	$7.50	Basic Delivery Charge	$27.36
1st 15 dk	$4.898	Distribution Delivery	$0.634
Over 15 dk	$4.399	Cost of Gas	$3.632

1/ Rate effective December 1, 2002.
2/ Includes December 2002 Cost of Gas based on .86% loss factor plus surcharge.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE (LARGE METERS)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	207	$933.08	$937.78	$4.70	0.50%
February	159	721.93	733.01	11.08	1.53%
March	159	721.93	733.01	11.08	1.53%
April	98	453.59	472.79	19.20	4.23%
May	61	290.82	314.95	24.13	8.30%
June	37	185.25	212.56	27.31	14.74%
July	25	132.46	161.37	28.91	21.83%
August	25	132.46	161.37	28.91	21.83%
September	49	238.04	263.75	25.71	10.80%
October	86	400.80	421.60	20.80	5.19%
November	135	616.35	630.63	14.28	2.32%
December	184	831.90	839.66	7.76	0.93%
Total	1,225	$5,658.61	$5,882.48	$223.87	3.96%

PRESENT RATE 70: 1/		PROPOSED RATE 70: 2/	
Base Rate	$15.00	Basic Delivery Charge	$54.72
1st 15 dk	$4.898	Distribution Delivery	$0.634
Over 15 dk	4.399	Cost of Gas	$3.632

1/ Rate effective December 1, 2002.
2/ Includes December 2002 Cost of Gas based on .86% loss factor plus surcharge.

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. 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 heating season defined as 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.

EFFECTIVE DATE:

Adjustments under this DDSM will commence in May 2003 and continue through April 2004. The DDSM will be recalculated on an annual basis and a new DDSM will be filed to be effective May 1 each year thereafter.

DISTRIBUTION DELIVERY STABILIZATION MECHANISM:

A DDSM will be determined for each rate schedule subject to the DDSM and shall be expressed as rate per dk. Monthly bills beginning with the first billing cycle following May 1, 2003 and each May 1st thereafter, will be adjusted (decreased or increased) by the application of a DDSM rate computed in accordance with the procedures based on temperature conditions for the winter heating season beginning November 1, 2002 ending March 31, 2003, and each heating season thereafter, compared to normal temperature levels established in the most recent general rate case. The DDSM rate will be stated as a surcharge or credit on all rate schedules to which the DDSM is applicable. A DDSM rate will be computed for each applicable rate schedule to be effective for a period of one year. Following the initial one-year term, and annually thereafter, the DDSM rate calculation shall include any over or under collection of DDSM revenue from the preceding twelve-month recovery period.

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

Section No. 3
Original Sheet No. 28.1

DISTRIBUTION DELIVERY STABILIZATION MECHANISM – Rate 87

Page 2 of 3

DDSM RATE CALCULATION:

A DDSM shall be determined for each rate schedule subject to the DDSM and shall be expressed as a rate per dk. In order to calculate the respective DDSM rates, the winter season HDD variation from the normal 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 and then divided by the average annual use per customer to determine a dollar amount per dk.

$$DDSM_i = \frac{R_i\,(DDF_i\,(NDD - ADD)) + (PDDSM_i - ADDSM_i)}{ANU_i}$$

Where:

$DDSM_i$ = Distribution Delivery Stabilization dollar amount per dk

i = Applicable rate class subject to the DDSM

R_i = Applicable Distribution Delivery Charge per dk

DDF_i = Temperature sensitive use per customer per degree day

NDD = Normal degree days for the winter service period

ADD = Actual degree days for the winter service period

ANU_i = Average normal use per customer for the prospective twelve month period

$PDDSM_i$ = Projected DDSM revenue from the preceding twelve month period

$ADDSM_i$ = Actual DDSM revenue recovered from the preceding twelve month period

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

Section No. 3
Original Sheet No. 28.2

DISTRIBUTION DELIVERY STABILIZATION MECHANISM – Rate 87

Page 3 of 3

DEFINITIONS:

Heating Degree Days	-	The difference between the average of the daily high and low temperature subtracted from 60 degrees Fahrenheit.
Normal Degree Days	-	The heating degree days that are based on the 30 year average ending June 30, 2001.
Actual Degree Days	-	The actual degree days reported by National Weather Service Stations for applicable service areas in South Dakota weighted by customers.

MONTANA-DAKOTA UTILITIES CO.

DOCKET NO. NG02-____

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. NG02-____

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MONTANA-DAKOTA UTILITIES CO.

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MONTANA-DAKOTA UTILITIES CO.

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MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
JUNE 30, 2001 AND
JUNE 30, 2002

	2001	2002
Assets and Other Debits		
Utility Plant	$816,121,930	$829,675,682
Construction Work in Progress	8,480,008	10,958,320
Less Acc. Provision for Depreciation and Amortization	461,088,649	484,268,567
Net Utility Plant	363,513,289	356,365,435
Gas Stored Underground - Noncurrent	1,195,374	2,795,330
Other Property and Investments		
Nonutility Property	136,603	141,898
(Less) Accum. Prov. for Depr. And Amort.	30,724	42,064
Investment in Subsidiary Companies	864,268,803	1,015,453,576
Other investments	24,030,708	25,962,623
Net Other Property and Investments	888,405,390	1,041,516,033
Current and Accrued Assets		
Cash	(1,840,467)	5,538,010
Special Deposits	1,200	1,200
Working Funds	17,031	15,962
Temporary Cash Investments	8,813,879	3,971,642
Customer Accounts Receivable	25,934,859	18,330,962
Other Accounts Receivable	2,395,281	1,305,667
(Less) Accum.Prov. For Uncollectible Acct. - Credit	511,028	327,644
Accounts Receivable from Assoc.Companies	12,563,869	13,768,368
Fuel Stock	2,019,109	2,163,934
Plant Materials and Operating Supplies	6,514,143	6,503,328
Merchandise	944,277	929,133
Stores Expense Undistributed	6,345	4,670
Gas Stored Underground - Current	4,355,827	1,585,814
Prepayments	4,171,126	4,496,053
Accured Utility Revenues	5,503,068	4,654,916
Miscellaneous Current and Accrued Assets	673,128	13,616,667
Total Current and Accrued Assets	71,561,647	76,558,682
Deferred Debits		
Unamortized Debt Expense	1,324,799	1,190,635
Other Regulatory Assets	3,654,473	3,286,453
Prelim. Survey and Investigation Charges	66,233	902,352
Clearing Accounts	(309,267)	39,895
Miscellaneous Deferred Debits	8,249,217	18,561,545
Unamortized Loss on Reaquired Debt	7,477,047	6,228,403
Accumulated Deferred Income Taxes	20,182,201	21,046,248
Unrecovered Purchased Gas Costs	(14,054,229)	(18,674,874)
Total Deferred Debits	26,590,474	32,580,657
Total Assets and Other Debits	$1,351,266,174	$1,509,816,137

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
JUNE 30, 2001 AND
JUNE 30, 2002

	2001	2002
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$68,273,213	$71,664,751
Preferred Stock Issued	16,500,000	16,400,000
Premium on Capital Stock	604,458,340	691,793,325
Other Paid in Capital	0	(1,685,461)
(Less) Capital Stock Expense	2,931,286	2,981,130
Retained Earnings	41,383,425	41,972,483
Unappropriated Undistributed Sub Earnings	305,460,452	368,251,110
Total Proprietary Capital	1,033,144,144	1,185,415,078
Long-Term Debt		
Bonds	130,850,000	130,850,000
Other Long-Term Debt	2,740,019	7,000,000
(Less) Unamortized Discount on Long-Term Debt-Debit	47,784	43,339
Total Long-Term Debt	133,542,235	137,806,661
Other Noncurrent Liabilities		
Accumulated Provision for Injuiries and Damages	1,421,290	1,482,288
Accumulated Provision for Pensions and Benefits	17,269,907	24,893,593
Accumulated Provision for Rate Refunds	0	373,172
Total Other Noncurrent Liabilities	18,691,197	26,749,053
Current and Accrued Liabilities		
Accounts Payable	14,543,161	12,725,250
Accounts Payable to Associated Companies	5,299,881	4,565,562
Customer Deposits	1,216,050	1,449,250
Taxes Accrued	15,496,777	13,689,029
Interest Accrued	2,300,213	2,293,662
Dividends Declared	15,157,424	16,616,834
Tax Collections Payable	1,265,891	1,165,038
Miscellaneous Current and Accrued Liabilities	13,414,190	10,477,436
Total Current and Accrued Assets	68,693,587	62,982,061
Deferred Credits		
Customer Advances for Construction	2,737,891	1,755,967
Accumulated Deferred Investment Tax Credit	4,003,204	3,340,916
Other Deferred Credits	3,020,149	9,189,344
Other Regulatory Liabilities	15,928,271	16,863,069
Accumulated Deferred Income Taxes	71,505,496	65,713,988
Total Deferred Credits	97,195,011	96,863,284
Total Liabilities and Equity	$1,351,266,174	$1,509,816,137

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

June 30, 2002 and 2001
(Unaudited)

1. **Basis of presentation**

The accompanying consolidated interim financial statements were prepared in conformity with the basis of presentation reflected in the consolidated financial statements included in the Annual Report to Stockholders for the year ended December 31, 2001 (2001 Annual Report), and the standards of accounting measurement set forth in Accounting Principles Board Opinion No. 28 and any amendments thereto adopted by the Financial Accounting Standards Board. Interim financial statements do not include all disclosures provided in annual financial statements and, accordingly, these financial statements should be read in conjunction with those appearing in the Company's 2001 Annual Report. The information is unaudited but includes all adjustments which are, in the opinion of management, necessary for a fair presentation of the accompanying consolidated interim financial statements.

2. **Allowance for doubtful accounts**

The Company's allowance for doubtful accounts as of June 30, 2002 and 2001, and December 31, 2001 was $8.4 million, $4.3 million and $5.8 million, respectively.

3. **Seasonality of operations**

Some of the Company's operations are highly seasonal and revenues from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Accordingly, the interim results for particular segments, and for the Company as a whole, may not be indicative of results for the full fiscal year.

4. **Cash flow information**

Cash expenditures for interest and income taxes were as follows:

	Six Months Ended June 30,	
	2002	2001
	(In thousands)	
Interest, net of amount capitalized	$ 19,236	$ 20,399
Income taxes	$ 40,589	$ 45,754

5. **Reclassifications**

Certain reclassifications have been made in the financial statements for the prior period to conform to the current presentation. Such reclassifications had no effect on net income or stockholders' equity as previously reported.

6. **New accounting standards**

In June 2001, the Financial Accounting Standards Board (FASB) approved Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). 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 upon settlement. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Company will adopt SFAS No. 143 on January 1, 2003, but has not yet quantified the effects of adopting SFAS No. 143 on its financial position or results of operations.

In April 2002, the FASB approved Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS No. 145). 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 Accounting Principles Board 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 Company has not yet quantified the effects of adopting SFAS No. 145 on its financial position or results of operations.

In June 2002, the Emerging Issues Task Force (EITF) adopted the position in EITF Issue No. 02-3, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities,' and No. 00-17, 'Measuring the Fair Value of Energy-related Contracts in Applying Issue No. 98-10'" (EITF No. 02-3) that mark-to-market gains and losses on energy trading contracts should be reported net in the income statement whether or not settled physically in financial statements issued for periods ending after July 15, 2002. EITF No. 02-3 states that all comparative financial

statements should be reclassified to conform to this consensus. Although this new accounting guidance will require the Company's mark-to-market gains and losses on energy trading contracts to be shown net on the income statement, it is not expected to impact the overall financial position or results of operations of the Company. The Company will apply this consensus to financial statements issued for periods ending after July 15, 2002, but has not yet quantified the financial statement effect from this guidance.

In June 2002, the FASB approved Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS No. 146). SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)" (EITF No. 94-3). SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF No. 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. The Company has not yet determined the effect, if any, of the adoption of SFAS No. 146.

7. **Derivative instruments**

The Company utilizes derivative instruments, including natural gas and oil price swap and natural gas collar agreements, to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on the Company's forecasted sales of natural gas and oil production. The following information should be read in conjunction with Note 3 in the Company's Notes to Consolidated Financial Statements in the 2001 Annual Report.

For the three months and six months ended June 30, 2002 and 2001, the amount of hedge ineffectiveness recognized was immaterial. For the three months and six months ended June 30, 2002 and 2001, the Company 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.

As of June 30, 2002, the maximum length of time over which the Company is hedging its exposure to the variability in future cash flows for forecasted transactions is 18 months. The Company estimates that net gains of approximately $2.1 million will be reclassified from accumulated other comprehensive income into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions

affect earnings within the twelve months between July 1, 2002 and June 30, 2003.

8. **Comprehensive income**

On January 1, 2001, the Company recorded a cumulative-effect adjustment in accumulated other comprehensive loss to recognize all derivative instruments designated as hedges at fair value. As of June 30, 2002 and 2001, the Company has recorded unrealized gains and losses on natural gas and oil price swap and collar agreements and an interest rate swap agreement which qualify for hedge accounting. As of June 30, 2002, the Company also recorded a minimum pension liability adjustment. These amounts are reflected in the following table.

The Company's comprehensive income, and the components of other comprehensive income, net of taxes, were as follows:

	Three Months Ended June 30,	
	2002	2001
	(In thousands)	
Net income	$ 24,853	$ 43,417
Other comprehensive income (loss) --		
Net unrealized gain on derivative instruments qualifying as hedges:		
Net unrealized gain on derivative instruments arising during the period, net of tax of $1,110 and $2,413 in 2002 and 2001, respectively	1,700	3,755
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $58 and $172 in 2002 and 2001, respectively	90	(263)
Net unrealized gain on derivative instruments qualifying as hedges	1,610	4,018
Minimum pension liability adjustment, net of tax of $2,781	(4,340)	---
	(2,730)	4,018
Comprehensive income	$ 22,123	$ 47,435

	Six Months Ended June 30, 2002	2001
	(In thousands)	
Net income	$ 48,575	$ 76,103
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	---	(6,080)
Net unrealized gain on derivative instruments arising during the period, net of tax of $574 and $3,428 in 2002 and 2001, respectively	880	5,309
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $888 and $2,472 in 2002 and 2001, respectively	1,360	(3,786)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(480)	3,015
Minimum pension liability adjustment, net of tax of $2,781	(4,340)	---
	(4,820)	3,015
Comprehensive income	$ 43,755	$ 79,118

9. **Goodwill and other intangible assets**

In June 2001, the FASB approved Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). SFAS No. 142 changes the accounting for goodwill and intangible assets and requires that goodwill no longer be amortized but be tested for impairment at least annually at the reporting unit level in accordance with SFAS No. 142. Recognized intangible assets with determinable useful lives should be amortized over their useful life and reviewed for impairment in accordance with Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). The provisions of SFAS No. 142 are effective for fiscal years beginning after December 15, 2001, except for provisions related to the nonamortization and amortization of goodwill and intangible assets acquired after June 30, 2001, which were subject immediately to the provisions of SFAS No. 142. The Company adopted SFAS No. 142 on January 1, 2002. SFAS No. 142 requires a transitional goodwill impairment test at each reporting unit within six months of the date of adoption of SFAS No. 142. However, the amounts used in the transitional goodwill impairment testing shall be measured as of January 1, 2002. The Company completed its transitional goodwill impairment testing and determined that no impairment exists as of January 1, 2002. Therefore, no impairment loss has been recorded for

the three months and six months ended June 30, 2002, in connection with the adoption of SFAS No. 142.

On January 1, 2002, in accordance with SFAS No. 142, the Company ceased amortization of its goodwill recorded in business combinations which 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 share to the amounts adjusted for the exclusion of goodwill amortization net of the related income tax effect is as follows:

	Three Months Ended June 30,	
	2002	2001
	(In thousands, except per share amounts)	
Reported earnings on common stock	$ 24,664	$ 43,226
Add: Goodwill amortization, net of tax	---	913
Adjusted earnings on common stock	$ 24,664	$ 44,139
Reported earnings per common share -- basic	$ .35	$ .64
Add: Goodwill amortization, net of tax	---	.02
Adjusted earnings per common share -- basic	$ .35	$ .66
Reported earnings per common share -- diluted	$ .35	$ .63
Add: Goodwill amortization, net of tax	---	.02
Adjusted earnings per common share -- diluted	$ .35	$ .65

	Six Months Ended June 30, 2002	2001
	(In thousands, except per share amounts)	
Reported earnings on common stock	$ 48,197	$ 75,722
Add: Goodwill amortization, net of tax	---	1,793
Adjusted earnings on common stock	$ 48,197	$ 77,515
Reported earnings per common share -- basic	$ .69	$ 1.14
Add: Goodwill amortization, net of tax	---	.03
Adjusted earnings per common share -- basic	$ .69	$ 1.17
Reported earnings per common share -- diluted	$ .68	$ 1.13
Add: Goodwill amortization, net of tax	---	.02
Adjusted earnings per common share -- diluted	$ .68	$ 1.15

The changes in the carrying amount of goodwill for the six months ended June 30, 2002, by business segment are as follows:

	Balance as of January 1, 2002	Net Goodwill Acquired During the Year	Balance as of June 30, 2002
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	61,909	(738)	61,171
Pipeline and energy services	9,336	158	9,494
Natural gas and oil production	---	---	---
Construction materials and mining	102,752	8,604	111,356
Total	$ 173,997	$ 8,024	$ 182,021

Included in other intangible assets on the Company's Consolidated Balance Sheets are the following:

	June 30, 2002	June 30, 2001	December 31, 2001
		(In thousands)	
Amortizable intangible assets:			
Leasehold rights	$ 79,005	$ 65,580	$ 72,955
Accumulated amortization	(1,524)	(868)	(1,149)
	77,481	64,712	71,806
Noncompete agreements	12,090	12,030	12,034
Accumulated amortization	(9,096)	(8,456)	(8,811)
	2,994	3,574	3,223
Other	5,149	1,347	1,377
Accumulated amortization	(215)	(133)	(172)
	4,934	1,214	1,205
Total	$ 85,409	$ 69,500	$ 76,234

Amortization expense for intangible assets for the three months and six months ended June 30, 2002, was approximately $472,000 and $703,000, respectively. Estimated amortization expense for intangible assets is $2.3 million in 2002, $2.6 million in 2003, $2.3 million in 2004, $2.3 million in 2005, $2.3 million in 2006 and $74.3 million thereafter.

10. Common stock

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.

11. 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's operations are conducted through six business segments. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consists of an investment in a natural gas fired electric generating station in Brazil. The electric segment generates, transmits and distributes electricity and the natural gas distribution segment distributes natural gas. These operations also supply related value-added products and services in the northern Great Plains. The utility services segment consists

of a diversified infrastructure company specializing in engineering, design and build capability for electric, gas and telecommunication utility construction, as well as industrial and commercial electrical, exterior lighting and traffic signalization throughout most of the United States. Utility services provides related specialty equipment manufacturing sales and rental services. The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. Energy-related marketing and management services as well as cable and pipeline locating services also are provided. The pipeline and energy services segment includes investments in domestic and international growth opportunities. 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 in the Gulf of Mexico. The construction materials and mining segment mines aggregates and markets crushed stone, sand, gravel and other related construction materials, including ready-mixed concrete, cement and asphalt, as well as value-added products and services in the north central and western United States, including Alaska and Hawaii.

In 2001, the Company sold its coal operations to Westmoreland Coal Company for $28.2 million in cash, including final settlement cost adjustments. The sale of the coal operations was effective April 30, 2001. Included in the sale were active coal mines in North Dakota and Montana, coal sales agreements, reserves and mining equipment, and certain development rights at the former Gascoyne Mine site in North Dakota. The Company retains ownership of coal reserves and leases at its former Gascoyne Mine site. The Company recorded a gain of $11.0 million ($6.6 million after tax) included in other income - net on the Company's Consolidated Statements of Income from the sale in the second quarter of 2001.

Segment information follows the same accounting policies as described in Note 1 of the Company's 2001 Annual Report. Segment information included in the accompanying Consolidated Statements of Income is as follows:

	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Three Months Ended June 30, 2002			
Electric	$ 36,292	$ ---	$ 1,673
Natural gas distribution	34,120	---	(815)
Utility services	116,344	---	834
Pipeline and energy services	36,110	9,267	2,750
Natural gas and oil production	27,775	15,989	9,341
Construction materials and mining	229,577	---	10,881
Intersegment eliminations	---	(25,256)	---
Total	$ 480,218	$ ---	$ 24,664
Three Months Ended June 30, 2001			
Electric	$ 38,036	$ ---	$ 2,152
Natural gas distribution	41,246	---	(1,547)
Utility services	77,183	---	3,873
Pipeline and energy services	147,111	7,432	3,383
Natural gas and oil production	40,517	14,884	17,888
Construction materials and mining	201,153	1,172*	17,477
Intersegment eliminations	---	(22,316)	---
Total	$ 545,246	$ 1,172*	$ 43,226

* In accordance with the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Regulation" (SFAS No. 71), intercompany coal sales are not eliminated.

	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Six Months Ended June 30, 2002			
Electric	$ 76,362	$ ---	$ 5,164
Natural gas distribution	105,832	---	3,701
Utility services	224,631	---	2,184
Pipeline and energy services	55,910	32,017	5,577
Natural gas and oil production	76,509	29,663	30,411
Construction materials and mining	322,909	---	1,160
Intersegment eliminations	---	(61,680)	---
Total	$ 862,153	$ ---	$ 48,197
Six Months Ended June 30, 2001			
Electric	$ 80,989	$ ---	$ 6,959
Natural gas distribution	182,100	---	1,127
Utility services	144,502	4	5,917
Pipeline and energy services	395,387	28,806	5,761
Natural gas and oil production	89,732	37,301	45,920
Construction materials and mining	289,939	5,016*	10,038
Intersegment eliminations	---	(66,111)	---
Total	$1,182,649	$ 5,016*	$ 75,722

* In accordance with the provisions of SFAS No. 71, intercompany coal sales are not eliminated.

On April 1, 2000, Fidelity Exploration & Production Company (Fidelity), an indirect wholly 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 for an amount as specified in the agreement. On July 10, 2002, Fidelity purchased the Seller's Option Interest.

12. **Acquisitions**

During the first six months of 2002, the Company acquired construction materials and mining businesses in Minnesota and Montana, an energy development company in Montana and a utility services company in California, none of which was individually material. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $56.8 million.

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. 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 the effects of the above acquisitions are not presented as such acquisitions were not material to the Company's financial position or results of operations.

13. **Regulatory matters and revenues subject to refund**

On June 10, 2002, Montana-Dakota filed with the Wyoming Public Service Commission (WYPSC) for a natural gas rate increase. The Company is requesting a total of $662,000 annually or 5.6 percent above current rates.

On May 20, 2002, Montana-Dakota filed with the Montana Public Service Commission (MTPSC) for a natural gas rate increase. The Company is requesting a total of $3.6 million annually or 6.5 percent above current rates.

On April 12, 2002, Montana-Dakota filed with the North Dakota Public Service Commission (NDPSC) for a natural gas rate increase. The Company is requesting a total of $2.8 million annually or 4.1 percent above current rates.

The NDPSC authorized its Staff to initiate an investigation into the earnings levels of Montana-Dakota's North Dakota electric operations based on Montana-Dakota's 2000 Annual Report to the NDPSC. The investigation was based on a complaint filed with the NDPSC on September 7, 2001, by the NDPSC Staff. On April 24, 2002, the NDPSC issued an Order requiring Montana-Dakota to reduce its North Dakota electric rates by $4.3 million annually, effective May 8, 2002. On April 25, 2002, Montana-Dakota filed an appeal of the NDPSC Order in the North Dakota South Central Judicial District Court (District Court). The filing also requested a stay of the effectiveness of the NDPSC Order while the appeal is pending.

Montana-Dakota is challenging the NDPSC's determination of the level of electricity sales to other utilities expected to be received by Montana-Dakota. On May 2, 2002, the District Court granted Montana-Dakota's request for a stay of a portion of the $4.3 million annual rate reduction ordered by the NDPSC. Accordingly, Montana-Dakota implemented an annual rate reduction of $800,000 effective with service rendered on and after May 8, 2002, rather than the $4.3 million annual reduction ordered by the NDPSC. The remaining $3.5 million is subject to refund if Montana-Dakota does not prevail in this proceeding.

Reserves have been provided for the revenues that have been collected subject to refund with respect to Montana-Dakota's pending electric rate reduction.

In December 1999, Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of the Company, filed a general natural gas rate change application with the Federal Energy Regulatory Commission (FERC). Williston Basin began collecting such rates effective June 1, 2000, subject to refund. In May 2001, the Administrative Law Judge issued an initial decision on Williston Basin's natural gas rate change application, which matter is currently pending before and subject to revision by the FERC.

Reserves have been provided for a portion of the revenues that have been collected subject 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.

14. **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 March 1997, 11 natural gas producers filed suit in North Dakota Southwest Judicial District Court (North Dakota District Court) against Williston Basin and the Company. The natural gas producers had processing agreements with Koch Hydrocarbon Company (Koch). Williston Basin and the Company had natural gas purchase contracts with Koch. The natural gas producers alleged they were entitled to damages for the breach of Williston Basin's and the Company's contracts with Koch although no specific damages were stated. A similar suit was filed by Apache Corporation (Apache) and Snyder Oil Corporation (Snyder) in North Dakota Northwest Judicial District Court in December 1993. The North Dakota Supreme Court in December 1999 affirmed the North Dakota Northwest Judicial District Court decision dismissing Apache's and Snyder's claims against Williston Basin and the Company. Based in part upon the decision of the North Dakota Supreme Court affirming the dismissal of the claims brought by Apache and Snyder, Williston Basin and the Company filed motions for summary judgment to dismiss the claims of the 11 natural gas producers. The motions for summary judgment were granted by the North Dakota District Court in July 2000. In March 2001, the North Dakota District Court entered a final judgment on the July 2000 order granting the motions for summary judgment. In May 2001, the 11 natural gas producers appealed the North Dakota District Court's decision by filing a Notice of Appeal with the North Dakota Supreme Court. Oral argument was held before the North Dakota Supreme Court in December 2001. On April 16, 2002, the North Dakota Supreme Court affirmed the summary judgment entered by the North Dakota District Court. On April 30, 2002, the 11 natural gas producers filed a petition for rehearing by the North Dakota Supreme Court. On May 17, 2002, the North Dakota Supreme Court denied the 11 natural gas producers petition for rehearing.

Williston Basin and the Company believe the claims of the 11 natural gas producers are without merit and intend to continue vigorously contesting this suit. Williston Basin and the Company believe it is not probable that the 11 natural gas producers will ultimately succeed given the current status of the litigation.

In July 1996, Jack J. Grynberg (Grynberg) filed suit in United States District Court for the District of Columbia (U.S. District Court) against Williston Basin and over 70 other natural gas pipeline companies. 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 March 1997, the U.S. District Court dismissed the suit without prejudice and the dismissal was affirmed by the United States Court of Appeals for the D.C. Circuit in October 1998. In June 1997, Grynberg filed a similar Federal False Claims Act suit against

Williston Basin and Montana-Dakota and filed over 70 other separate similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. 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 (Federal District Court). Oral argument on motions to dismiss was held before the Federal District Court in March 2000. In May 2001, the Federal District Court denied Williston Basin's and Montana-Dakota's motion to dismiss. The matter is currently pending.

The Quinque Operating Company (Quinque), on behalf of itself and subclasses of gas producers, royalty owners and state taxing authorities, instituted a legal proceeding in State District Court for Stevens County, Kansas, (State District Court) against over 200 natural gas transmission companies and producers, gatherers, and processors of natural gas, including Williston Basin and Montana-Dakota. The complaint, which was served on Williston Basin and Montana-Dakota in September 1999, contains allegations of improper measurement of the heating content and volume of all natural gas measured by the defendants other than natural gas produced from federal lands. In response to a motion filed by the defendants in this suit, the Judicial Panel on Multidistrict Litigation transferred the suit to the Federal District Court for inclusion in the pretrial proceedings of the Grynberg suit. Upon motion of plaintiffs, the case has been remanded to State District Court. In September 2001, the defendants in this suit filed a motion to dismiss with the State District Court. The matter is currently pending.

Williston Basin and Montana-Dakota believe the claims of Grynberg and Quinque are without merit and intend to vigorously contest these suits. Williston Basin and Montana-Dakota believe it is not probable that Grynberg and Quinque will ultimately succeed given the current status of the litigation.

15. **Environmental matters**

In December 2000, Morse Bros., Inc. (MBI), an indirect wholly owned subsidiary of the Company, was named by the United States Environmental Protection Agency (EPA) as a Potentially Responsible Party in connection with the cleanup of a commercial property site, now owned by MBI, 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. Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon State Department of Environmental Quality and other information available, MBI does not believe it is a Responsible

Party. In addition, MBI intends to seek indemnity for any and all liabilities incurred in relation to the above matters from Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, 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.

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
SEPTEMBER 30, 2001 AND
SEPTEMBER 30, 2002

	2001	2002
Assets and Other Debits		
Utility Plant	$814,024,974	$833,984,752
Construction Work in Progress	10,664,233	17,408,083
(Less) Acc. Provision for Depreciation and Amortization	465,829,580	490,079,956
Net Utility Plant	358,859,627	361,312,879
Gas Stored Underground - Noncurrent	1,195,374	2,795,330
Other Property and Investments		
Nonutility Property	137,289	162,639
(Less) Accum. Prov. for Depr. And Amort.	33,533	44,940
Investment in Subsidiary Companies	925,514,241	1,052,337,847
Other investments	26,963,056	26,360,880
Net Other Property and Investments	952,581,053	1,078,816,426
Current and Accrued Assets		
Cash	25,981,672	4,442,671
Special Deposits	1,200	1,200
Working Fund	16,023	130,994
Temporary Cash Investments	2,520,766	3,606,488
Customer Accounts Receivable	15,369,432	13,710,278
Other Accounts Receivable	2,098,468	956,901
(Less) Accum. Prov. For Uncollectible Acct. - Credit	227,522	232,881
Accounts Receivable from Assoc. Companies	11,370,303	14,852,562
Fuel Stock	1,785,809	2,101,207
Plant Materials and Operating Supplies	6,605,641	6,562,260
Merchandise	935,953	948,864
Stores Expense Undistributed	9,914	10,046
Gas Stored Underground - Current	23,525,756	27,816,973
Prepayments	12,107,736	11,580,859
Accrued Utility Revenues	6,807,009	5,403,312
Miscellaneous Current and Accrued Assets	540,704	34,157
Total Current and Accrued Assets	109,448,864	91,925,891
Deferred Debits		
Unamortized Debt Expenses	1,291,187	1,157,166
Other Regulatory Assets	3,562,468	3,325,807
Prelim. Survey and Investigation Charges	146,697	1,293,822
Clearing Accounts	169,975	911,048
Miscellaneous Deferred Debits	9,008,523	18,964,034
Unamortized Loss on Reacquired Debt	7,153,171	5,927,957
Accumulated Deferred Income Taxes	17,023,732	18,569,022
Unrecovered Purchased Gas Costs	(24,351,205)	(18,949,990)
Total Deferred Debits	14,004,548	31,198,866
Total Assets and Other Debits	$1,436,089,466	$1,566,049,392

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
SEPTEMBER 30, 2001 AND
SEPTEMBER 30, 2002

	2001	2002
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$69,386,316	$71,681,396
Preferred Stock Issued	16,500,000	16,400,000
Premium on Capital Stock	629,599,156	693,120,235
Accumulated Other Comprehensive Income	0	(5,043,869)
(Less) Capital Stock Expense	2,943,751	2,981,130
Retained Earnings	41,236,938	39,669,304
Unappropriated Undistributed Sub Earnings	340,513,567	407,150,234
Total Proprietary Capital	1,094,292,226	1,219,996,170
Long-Term Debt		
Bonds	130,850,000	130,850,000
Other Long-Term Debt	2,737,983	25,000,000
(Less) Unamortized Discount on Long-Term Debt-Debit	46,672	42,227
Total Long-Term Debt	133,541,311	155,807,773
Other Noncurrent Liabilities		
Accumulated Provision for Injuries and Damages	1,355,150	1,470,694
Accumulated Provision for Pensions and Benefits	17,523,472	25,194,143
Accumulated Provision for Rate Refunds	0	1,336,705
Total Other Noncurrent Liabilities	18,878,622	28,001,542
Current and Accrued Liabilities		
Accounts Payable	14,641,561	12,302,325
Accounts Payable to Associated Companies	29,519,625	4,784,328
Customer Deposits	1,306,235	1,430,331
Taxes Accrued	22,479,315	14,887,231
Interest Accrued	4,710,777	4,702,903
Dividends Declared	15,839,836	17,335,078
Tax Collections Payable	805,921	745,777
Miscellaneous Current and Accrued Liabilities	8,986,211	10,538,139
Total Current and Accrued Assets	98,289,481	66,726,112
Deferred Debits		
Customer Advances for Construction	1,597,460	1,765,888
Accumulated Deferred Investment Tax Credit	3,818,131	3,190,343
Other Deferred Credits	3,363,612	9,111,095
Other Regulatory Liabilities	15,959,950	16,913,842
Accumulated Deferred Income Taxes	66,348,673	64,536,627
Total Deferred Credits	91,087,826	95,517,795
Total Liabilities and Equity	$1,436,089,466	$1,566,049,392

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MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING JUNE 30, 2002

Operating Income	
Electric Utility	
Operating Revenues	$164,209,713
Operating Expenses:	
Operation Expenses	90,930,470
Maintenance Expenses	10,893,861
Depreciation Expenses	19,484,870
Taxes Other Than Income Taxes	7,637,428
Income Taxes:	
Federal Taxes on Income	11,130,815
State Taxes on Income	1,789,317
Deferred Income Taxes	(1,681,637)
Total Electric Expenses	140,185,124
Net Electric Operation	$24,024,589
Gas Utility	
Operating Revenues	$179,121,063
Operating Expenses:	
Operation Expenses	155,321,107
Maintenance Expenses	2,779,026
Depreciation Expenses	9,485,168
Taxes Other Than Income Taxes	5,128,387
Income Taxes:	
Federal Taxes on Income	2,656,408
State Taxes on Income	700,958
Deferred Income Taxes	(1,915,331)
Total Gas Expenses	174,155,723
Net Gas Operation	$4,965,340
Net Utility Operating Income	$28,989,929
Revenues from Merchandising, Jobbing and Contract Work	$9,046,634
(Less) Costs and Exp. Of Merch., Jobbing and Contract Work	7,570,925
Revenues from Nonutility Operations	86,421
Equity in Earnings of Subsidiary Companies	107,386,658
Interest and Dividend Income	4,214,347
Miscellaneous Nonoperating Income	21,481
Gain on Disposition of Property	358,218
Total Other Income	113,542,834
Loss on Disposition of Property	0
Miscellaneous Income Deductions	2,767,869
Total Other Income Deductions	2,767,869

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING JUNE 30, 2002

Taxes other than Income Taxes	$13,516
Income Taxes - Federal	2,381,277
Income Taxes - State	(1,213,440)
Provision for Deferred Income Taxes	(1,055,229)
Investment Tax Credits	(662,288)
Total Taxes on Other Income and Deductions	(536,164)
Net Other Income and Deductions	$111,311,129
Interest On Long-Term Debt	9,922,627
Amortization of Debt Discount and Expense	1,387,253
Other Interest Expense	863,861
(Less) Allowance for Borrowed Funds used during Construction	193,122
Net Interest Charges	11,980,619
Net Income	$128,320,439

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING SEPTEMBER 30, 2002

Operating Income	
Electric Utility	
Operating Revenues	$157,570,177
Operating Expenses:	
Operation Expenses	90,983,122
Maintenance Expenses	10,687,326
Depreciation Expenses	19,459,256
Taxes Other Than Income Taxes	7,619,325
Income Taxes:	
Federal Taxes on Income	9,475,946
State Taxes on Income	1,558,472
Deferred Income Taxes	(2,235,517)
Total Electric Expenses	137,547,930
Net Electric Operation	$20,022,247
Gas Utility	
Operating Revenues	$177,233,473
Operating Expenses:	
Operation Expenses	153,484,602
Maintenance Expenses	2,742,871
Depreciation Expenses	9,586,013
Taxes Other Than Income Taxes	5,124,190
Income Taxes:	
Federal Taxes on Income	(1,007,000)
State Taxes on Income	369,372
Deferred Income Taxes	1,980,085
Total Gas Expenses	172,280,133
Net Gas Operation	$4,953,340
Net Utility Operating Income	$24,975,587
Revenues from Merchandising, Jobbing and Contract Work	$9,652,289
(Less) Costs and Exp. Of Merch., Jobbing and Contract Work	7,971,537
Revenues from Nonutility Operations	75,356
Equity in Earnings of Subsidiary Companies	114,272,667
Interest and Dividend Income	4,411,440
Miscellaneous Nonoperating Income	21,481
Gain on Disposition of Property	358,201
Total Other Income	120,819,897
Loss on Disposition of Property	0
Miscellaneous Income Deductions	2,672,578
Total Other Income Deductions	2,672,578

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING SEPTEMBER 30, 2002

Taxes Other than Income Taxes	13,516
Income Taxes - Federal	2,552,916
Income Taxes - State	(1,179,946)
Provision for Deferred Income Taxes	(1,079,452)
Investment Tax Credits	(627,788)
Total Taxes on Other Income and Deductions	(320,754)
Net Other Income and Deductions	$118,468,073
Interest On Long-Term Debt	$9,913,083
Amortization of Debt Discount and Expense	1,363,679
Other Interest Expense	836,074
(Less) Allowance for Borrowed Funds used during Construction	174,172
Net Interest Charges	$11,938,664
Net Income	$131,504,996

MDU RESOURCES GROUP, INC.
STATEMENT OF RETAINED EARNINGS
JUNE 30, 2002

Retained Earnings at June 30, 2001		$41,383,425
Unappropriated Undistributed Subsidiary Earnings at June 30, 2001		305,460,452
Retained Earnings at June 30, 2001		346,843,877
Net Income from Income Statement for the Twelve Months ended June 30, 2002		128,320,439
Dividend Appropriation of Surplus:		
4.50% Preferred Stock	$450,006	
4.70% Preferred Stock	235,001	
5.10% Preferred Stock	73,950	
Common Stock	64,181,766	64,940,723
Retained Earnings at June 30, 2002		$410,223,593

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PLANT IN SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	6/30/02	2002	2003
Plant in Service			
Distribution	$29,536,721	$30,449,566	$31,872,837
General	6,999,869	7,072,210	9,058,070
General - Intangible	137,373	137,373	135,079
Common	1,254,839	1,127,114	1,383,548
Common - Intangible	1,003,575	1,082,049	1,283,276
Plant in Service	$38,932,377	$39,868,312	$43,732,810
CWIP in Service	264,640		
Total Plant in Service	$39,197,017	$39,868,312	$43,732,810

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Acct. No.	Account	Balance 6/30/01	Balance 6/30/02	Average 6/30/02
	Distribution Plant			
374.1	Land	$29,992	$30,306	$30,149
374.2	Rights of Way	8,609	8,609	8,609
375	Structures	37,325	37,325	37,325
376	Mains	16,916,661	17,450,000	17,183,330
378	Meas. & Reg. Equip.-General	237,584	243,979	240,782
379	Meas. & Reg. Equip.-City Gate	58,623	58,623	58,623
380	Services	4,979,797	5,231,490	5,105,643
381	Positive Meters	5,533,498	5,815,113	5,674,305
383	Service Regulators	799,955	822,060	811,008
385	Ind. Meas. & Reg. Station Eqpt.	63,429	63,429	63,429
386.2	Other Property on Cust. Premise	170,931	170,931	170,931
387.1	Cathodic Protection Equip.	66,245	66,245	66,245
387.2	Other Distribution Equip.	86,342	86,342	86,342
	Total Distribution Plant	$28,988,991	$30,084,452	$29,536,721
	General Plant			
389	Land & Land Rights	$105,845	$582,076	$343,960
390	Structures and Improvements	633,712	3,786,180	2,209,946
391.1	Furniture and Fixtures	222,883	363,336	293,109
391.3	Computer Equip. - PC	203,253	212,289	207,771
392.1	Trans. Equip., Non-Unitized	35,859	35,859	35,859
392.2	Trans. Equip., Unitized	1,455,461	1,597,117	1,526,289
393	Stores Equipment	29,501	56,721	43,111
394.1	Tools,Shop&Gar. Eq.-Non-Un.	449,833	511,792	480,812
394.2	Tools,Shop&Gar. Eq.-Unitized	73,712	57,875	65,793
394.3	Vehicle Maint. Equip.	7,627	7,627	7,627
394.4	Vehicle Refueling Equip.	138,079	138,079	138,079
395	Laboratory Equipment	42,911	42,947	42,929
396.1	Power Operated Equip.	82,045	85,741	83,893
396.2	Work Equipment Trailers	1,147,411	1,132,033	1,139,722
397.1	Radio Comm. Equip.-Fixed	86,556	86,556	86,556
397.2	Radio Comm. Equip.-Mobile	116,726	116,726	116,726
397.3	General Tele. Comm. Equip.	40,478	47,773	44,126
397.5	Supervisory & Telemetering	84,774	84,779	84,777
397.6	Scada System	770	770	770
397.8	Network Equipment	11,480	17,991	14,736
398	Miscellaneous Equipment	33,276	33,279	33,278
	Total General Plant	$5,002,192	$8,997,546	$6,999,869
303	Intangible Plant - General	$139,667	$135,079	$137,373

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Acct. No.	Account	Balance 6/30/01	Balance 6/30/02	Average 6/30/02
	Common Plant			
389	Land & Land Rights	$39,663	$31,426	$35,544
390	Structures and Improvements	542,953	372,943	457,948
391.1	Furniture and Fixtures	191,249	156,632	173,940
391.2	Computer Equip.- Bull/AS400	6,077	6,671	6,374
391.3	Computer Equip. - PC	237,276	240,333	238,804
391.5	Computer Equip. - Other	53,317	58,283	55,800
392.1	Trans. Equip., Non-Unitized	1,154	1,265	1,210
392.2	Trans. Equip., Unitized	46,136	49,089	47,612
392.3	Aircraft	66,657	77,196	71,926
393	Stores Equipment	258	283	271
394.1	Tools,Shop&Gar. Eq.-Non-Un.	1,816	1,994	1,905
394.3	Vehicle Maint. Equip.	5,516	6,103	5,810
394.4	Vehicle Refueling Equip.	5,706	6,848	6,277
396.2	Work Equipment Trailers	3,372	8,160	5,766
397.1	Radio Comm. Equip.-Fixed	12,353	13,559	12,956
397.2	Radio Comm. Equip.-Mobile	16,465	18,072	17,269
397.3	General Tele. Comm. Equip.	28,269	28,933	28,601
397.5	Supervisory & Telemetering	142	156	149
397.8	Network Equipment	55,079	55,135	55,107
398	Miscellaneous Equipment	32,999	30,140	31,570
	Total Common Plant	$1,346,457	$1,163,221	$1,254,839
303	Intangible Plant - Common	$947,362	$1,059,787	$1,003,575
	Total Gas Plant in Service	$36,424,669	$41,440,085	$38,932,377

MONTANA-DAKOTA UTILITIES CO.
DETAILED COST OF PLANT
GAS UTILITY
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Acct. No.	Account	Balance @ 6/31/01	Additions	Retirements	Transfers	Balance @ 6/30/02	Average Balance
	Intangible Plant						
303	Misc. Intangible Plant	$477,530	$0	$0	$0	$477,530	$477,530
	Total Intangible Plant	$477,530	$0	$0	$0	$477,530	$477,530
	Distribution Plant						
374.1	Land	$109,234	$83	($83)	$315	$109,549	$109,392
374.2	Rights of Way	89,641	1,708	0	0	91,349	90,495
375	Structures & Improvements	521,210	0	0	0	521,210	521,210
376	Mains	76,988,162	1,651,431	(165,289)	0	78,474,304	77,731,233
378	Measuring & Regulating Equip. - Gen.	1,359,419	21,626	(4,325)	5,613	1,382,333	1,370,875
379	Measuring & Regulating Equip. - City Gate	1,009,137	0	0	0	1,009,137	1,009,137
380	Services	31,633,549	1,238,007	(108,638)	0	32,762,918	32,198,234
381	Meters	29,823,172	1,627,995	(315,582)	(4,401)	31,131,184	30,477,178
382	Meter Set Installations	0	0	(21,154)	0	(21,154)	(10,577)
383	Service Regulators	4,211,121	113,902	0	(853)	4,324,170	4,267,646
385	Industrial Measuring & Regulating Equip.	578,200	0	(561)	(359)	577,280	577,740
386.1	Misc. Property on Customers' Premise	1,680	0	0	0	1,680	1,680
386.2	Other Property on Customer Premise	432,811	0	0	0	432,811	432,811
387.1	Cathodic Protection Equipment	1,378,438	98,382	(20,289)	0	1,456,531	1,417,484
387.2	Other Distribution Equipment	557,184	0	0	0	557,184	557,184
	Total Distribution Plant	$148,692,958	$4,753,134	($635,921)	$315	$152,810,486	$150,751,722
	General Plant						
389	Land	$300,834	$631,768	($81,179)	($315)	$851,108	$575,971
390	Structures & Improvements	1,895,756	4,135,563	(469,369)	121,634	5,683,584	3,789,670
391.1	Office Furniture & Equipment	554,404	174,538	(10,795)	0	718,147	636,276
391.3	Computer Equip.-PC	754,589	30,743	(4,337)	0	780,995	767,792
392.1	Transportation Equipment - Non-Un.	141,003	13,998	(7,814)	0	147,187	144,095
392.2	Transportation Equipment - Unitized	5,584,431	763,699	(456,941)	20,772	5,911,961	5,748,196
393	Stores Equipment	165,409	35,517	(8,297)	0	192,629	179,019
394.1	Tools,Shop&Gar. Equip.-Non-Un.	2,403,141	188,977	(14,272)	0	2,577,846	2,490,493

DOCKET NO. ____
RULE 20:10:13:55
STATEMENT D
SCHEDULE D-1
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MONTANA-DAKOTA UTILITIES CO.
DETAILED COST OF PLANT
GAS UTILITY
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Acct. No.	Account	Balance @ 6/31/01	Additions	Retirements	Transfers	Balance @ 6/30/02	Average Balance
394.2	Tools,Shop&Gar. Equip.-Non-Un.	299,810	0	0	(15,837)	283,973	291,892
394.3	Vehicle Maintenance Equipment	31,177	0	0	0	31,177	31,177
394.4	Vehicle Refueling Equipment	365,532	0	(4,188)	0	361,344	363,438
395	Laboratory Equipment	271,033	2,074	0	0	273,107	272,070
396.1	Work Equipment Trailers	278,991	75,424	(5,815)	0	348,600	313,795
396.2	Power Operated Equipment	3,979,470	719,990	(674,234)	0	4,025,226	4,002,348
397.1	Radio Communication Equip. - Fixed	461,165	20,763	(14,760)	0	467,168	464,167
397.2	Radio Communication Equip. - Mobile	401,528	0	(1,427)	0	400,101	400,814
397.3	General Tele. Comm. Equip.	94,750	11,527	(4,855)	0	101,422	98,086
397.5	Supervisory & Tele. Equip.	124,167	0	0	0	124,167	124,167
397.6	Scada System	30,894	0	0	0	30,894	30,894
397.8	Network Equipment	23,119	7,219	0	0	30,338	26,729
398	Miscellaneous Equipment	142,443	5,331	(264)	0	147,510	144,976
	Total General Plant	$18,303,646	$6,817,131	($1,758,547)	$126,254	$23,488,484	$20,896,065
	Common Plant - Gas 1/						
	Total Common Plant	$19,061,313	$0	$0	$0	$18,708,504	$18,884,909
	Gas Plant Leased to Others						
386.3	CNG Demo/Lease	$25,773	$0	$0	$0	$25,773	$25,773
394.4	Vehicle Refueling Equipment	4,188	0	(4,188)	0	0	2,094
	Total Gas Plant Leased to Others	$29,961	$0	($4,188)	$0	$25,773	$27,867
	Total Gas Plant in Service	$186,565,408	$11,570,265	($2,398,656)	$126,569	$195,510,777	$191,038,093

1/ Common plant is either directly assigned or allocated to gas and electric plant. Total common plant additions, retirements and transfers for the twelve months ended June 30, 2002 are $2,150,562, $5,935,090, and ($291,787) respectively.

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MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Work Order #	Description	Location	Construction Period	Date Placed In-Service	Beginning Balance	Major Additions	Major Retirements	Ending Balance
	Gas Plant				$167,474,134			
J45819	Install main in Powerhorn subdivision (Contribution) - Sheridan	WY	5/96-10/96	10/21/96		($170,510)		
J114001	Replace low pressure main	MT	5/01-11/01	11/28/01		117,444		
J111910	Replace main on Highway 12 rebuild	MT	5/01-7/01	7/27/01		101,239		
J93941	Construct office building/service center - Rapid City	SD	12/00-1/02	1/28/02		4,122,160		
J101500	Remediation of gas plant site - Rapid City	SD	2/00-1/02	1/28/02		629,806		
J106177	Purchase furniture and shelving for new office/service center - Rapid City	SD	4/02-5/02	5/9/02		216,693		
J122823	Sale of office building - Rapid City	SD	3/02	3/31/02			429,385	
	Major projects Subtotal				167,474,134	5,016,832	429,385	
	Miscellaneous Projects					6,680,002	1,965,083	
	Subtotal				167,474,134	11,696,834	2,394,468	176,776,499
	Common Plant Allocated to Gas				19,061,313			18,708,504
	Total Gas Plant				$186,535,447			$195,485,003

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MONTANA-DAKOTA UTILITIES CO.
GAS CWIP IN SERVICE
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Work Order Number	Description	State	Total	Distribution	General	Common
J101500	Remediate gas plant site	SD	$119		$119	
J123362	Purchase meter prover	ND	9,581		9,581	
J127611	Reconstruction costs - General Office	ND	22,085			$22,085
Small items grouped 1/:						
(35)	Distribution	SD	221,502	$221,502		
(4)	General	SD	4,289		4,289	
(15)	Common		7,064			7,064
	Total		$264,640	$221,502	$13,989	$29,149

1/ Numbers in brackets indicate the Number of Work orders involved in each item of construction.

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2002-2003

Plant in Service	Plant in Service @ 12/31/01	Plant in Service @ 6/30/02 1/	Projected 2002 Plant Additions 2/	Projected 2002 Plant Retirements 3/	Projected 2002 Balance @ 12/31/02	Average 2002 Plant	Projected 2003 Plant Additions	Projected 2003 Plant Retirements	Projected 2003 Balance @ 12/31/03	Average 2003 Plant
Distribution	$29,712,346	$30,305,954	$936,897	($56,066)	$31,186,785	$30,449,566	$1,487,494	($115,391)	$32,558,888	$31,872,837
General										
Other General	2,249,590	6,093,329	33,859	(117,939)	6,009,249	4,129,420	55,797	(227,049)	5,837,997	5,923,623
Transportation Eqpt.	1,539,891	1,632,976	269,878	(85,731)	1,817,123	1,678,507	335,805	(190,798)	1,962,130	1,889,627
Tools & Work Eqpt.	1,285,253	1,285,230	25,558	(67,475)	1,243,313	1,264,283	133,563	(130,548)	1,246,328	1,244,820
Intangible	139,667	135,079		0	135,079	137,373		0	135,079	135,079
	5,214,401	9,146,614	329,295	(271,145)	9,204,764	7,209,583	525,165	(548,395)	9,181,534	9,193,149
Common										
Other Common	650,152	751,373	29,632	(38,583)	742,422	696,287	56,235	(76,247)	722,410	732,416
Computer Equipment	256,079	305,287	66,576	(15,676)	356,187	306,133	104,471	(36,580)	424,078	390,133
Transportation Eqpt.	110,443	127,550	5,439	(6,550)	126,439	118,441	333,130	(78,696)	380,873	253,656
Tools & Work Eqpt.	4,766	8,160		(419)	7,741	6,253		(795)	6,946	7,343
Intangible	955,687	1,059,787	151,432	(2,808)	1,208,411	1,082,049	156,135	(6,405)	1,358,141	1,283,276
Total Common	1,977,127	2,252,157	253,079	(64,036)	2,441,200	2,209,163	649,971	(198,723)	2,892,448	2,666,824
Total Plant in Service	$36,903,874	$41,704,725	$1,519,271	($391,247)	$42,832,749	$39,868,312	$2,662,630	($862,509)	$44,632,870	$43,732,810

1/ Includes CWIP in service.
2/ Plant additions for July - December 2002.
3/ One half of the annual retirements based on the ratio of retirements to plant for 1999 - 2001.
Adjusted to exclude new region office in 2002 and new aircraft in 2003.

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MONTANA-DAKOTA UTILITIES CO.
PLANT ADDITIONS - SUMMARY
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2002-2003

2002	
Distribution	$936,897
General	
Other	33,859
Transportation Eqpt.	269,878
Tools & Work Eqpt.	25,558
Total General	329,295
Common	
Other	29,632
Computer equipment	66,576
Transportation Eqpt.	5,439
Intangible	151,432
Total Common	253,079
Total Plant Additions	$1,519,271
2003	
Distribution	$1,487,494
General	
Other	55,797
Transportation Eqpt.	335,805
Work Eqpt.	133,563
Total General	525,165
Common	
Other	56,235
Computer equipment	104,471
Transportation Eqpt.	333,130
Intangible	156,135
Total Common	649,971
Total Plant Additions	$2,662,630

MONTANA-DAKOTA UTILITIES CO.
PLANT ADDITIONS
GAS UTILITY - SOUTH DAKOTA
PROJECTED 7/1/02 - 12/31/02

Acct.	Project No.	Description	Region	Plant Additions 7/1-12/31/02
		Distribution		
376	B13430G	Mains & Services-Growth	BH	$298,191
376	B13430R	Mains & Services-Replacement	BH	48,918
376	J131204	Install mains-Omaha St (Non-budget item)	BH	327,422
378	J120089	Replace Williston Basin SCADA-Rapid City	BH	14,412
378	B13434	Measuring and Regulating Equipment	BH	23,060
381	B90031	Meters	GO	181,958
383	B90032	Regulators	GO	36,018
387.1	B13435	Cathodic Protection	BH	6,918
		Total Distribution		936,897
		General		
391.1	B13442	Office equipment - Black Hills	BH	10,152
392.2	B13438	Vehicles	BH	269,878
394.1	B13443	Minor work equipment	BH	21,388
394.1	B90043	Minor work equipment	GO	882
396.2	B13439	Work equipment - Black Hills	BH	25,558
397.1	B13444	Communication equip. - Rapid City	BH	1,437
		Total General		329,295
		Common		
390	J76814	Remodel costs for Annex - GO	GO	5,702
391.1	J121109	Remodel 5th Floor - General Office	GO	2,173
391.1	B90082	Office Equipment	GO	2,747
391.1	J119514	Purchase furniture-Marketing Dept.	GO	6,732
391.3	B90080	Personal computers	GO	21,105
391.3	J106605	Replace ITRON equipment-MDU	GO	3,847
391.3	J120232	Purchase Toughbook PC's-MDT Replacemen	GO	21,383
391.3	J120012	Purchase mobile data equipment	GO	13,317
391.5	J120081	Install hardware/software-MobileFd	GO	1,875
391.5	J120082	Purchase bar coding equipment- mobile up	GO	5,049
392.2	B90078	Vehicles	GO	5,439
394.1	B90083	Minor work equipment	GO	286
397.1	B90084	Communication equipment	GO	1,283
397.4	J106252	Replace power line equipment	GO	2,049
397.8	B90081	Network equipment	GO	2,894
397.8	J106250	Modify fiber optic system	GO	5,766
		Total Common		101,647
303	J61813	GIS (GEMS) Project	GO	130,427
303	J120717	CIS enhancements	GO	21,005
		Total Common - Intangible		151,432
	Total			$1,519,271

MONTANA-DAKOTA UTILITIES CO.
PLANT ADDITIONS
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2003

Acct.	Project No.	Description	Region	Plant Additions
		Distribution		
376	B13430G	Mains & Services - growth	BH	$813,554
376	B13430R	Mains & Services - replacement	BH	167,166
376	J133707	Relocate mains	BH	40,311
376	J133781	Main Extension - Box Elder	BH	39,803
376	J133783	Main Extension - Black Hawk	BH	56,862
378	B13434	Measuring and Regulating Eqpt.	BH	28,227
381	B90031	Meters	GO	274,126
383	B90032	Regulators	GO	50,387
387.1	B13435	Cathodic Protection	BH	17,058
		Total Distribution		1,487,494
		General		
391.1	B13442	Office Equipment	BH	4,108
391.3	B13440	Computer Equip. - PC	BH	21,907
392.2	B13438	Vehicles	BH	335,805
394.1	B13443	Minor work equipment	BH	26,595
394.1	B90043	Minor work equipment	GO	880
396.2	B13439	Work equipment	BH	133,563
397.1	B13444	Communication equipment	BH	2,307
		Total General		525,165
		Common		
390	J76814	Remodel costs for Annex	GO	7,172
391.1	J121109	Remodel 5th floor	GO	2,424
391.1	B90082	Office Equipment	GO	12,794
391.1	J119514	Purchase furniture - Marketing	GO	7,375
391.3	J133994	Purchase imaging system	GO	12,430
391.3	B90080	Personal Computers	GO	33,237
391.3	J120232	Purchase toughbook PCs - MDT replacement	GO	13,562
391.3	J120233	Purchase 20 repl. MDT's - Mobile Up	GO	7,335
391.3	J120012	Purchase mobile data equipment	GO	4,162
391.5	J133977	Replace meter read system hardware	GO	33,745
392.2	B90078	Vehicles	GO	9,719
392.3	J136907	Replace Conquest aircraft	GO	323,411
394.1	B90083	Minor work equipment	GO	3,184
397.1	B90084	Communication equipment	GO	3,373
397.2	J119972	Purchase mobile radio equipment	GO	1,064
397.3	J133810	Purchase voice recorder - GO Comm	GO	1,687
397.4	J106252	Replace power line equipment	GO	3,243
397.8	B90081	Network equipment	GO	6,600
397.8	J106250	Modify fiber optic system	GO	7,319
		Total Common		493,836
		Intangible		
303	J61813	GIS (GEMS) Project	GO	129,493
303	J101617	Internet Bill PP system	GO	4,466
303	J133196	CIS Enhancements	GO	7,435
303	J133993	Implement One World	GO	7,384
303	J136784	Develop Internet wWebsite	GO	7,357
		Total Intangible		156,135
		Total		$2,662,630

MONTANA-DAKOTA UTILITIES CO.
AVERAGE ALLOCATED GAS PLANT IN SERVICE BALANCES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Acct. No.	Account	July Average	August Average	September Average	October Average	November Average	December Average	January Average	February Average	March Average	April Average	May Average	June Average	12 Months Average
	Distribution Plant													
374.1	Land	$29,992	$29,992	$29,992	$29,992	$29,992	$29,992	$29,992	$30,149	$30,306	$30,306	$30,306	$30,306	$30,110
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	37,325	37,325	37,325	37,325	37,325	37,325
376	Mains	16,920,257	16,946,864	16,965,506	16,978,717	17,062,693	17,236,633	17,346,039	17,361,929	17,394,206	17,416,072	17,427,711	17,442,868	17,208,291
378	Meas & Reg Equip-General	237,584	238,612	239,640	239,640	239,640	241,686	243,249	243,373	243,979	243,979	243,979	243,979	241,612
379	Meas & Reg Equip-City Gate	58,623	58,623	58,623	58,623	58,623	58,623	58,623	58,623	58,623	58,623	58,623	58,623	58,623
380	Services	4,986,620	5,005,037	5,023,333	5,039,390	5,065,791	5,108,738	5,151,577	5,178,041	5,191,923	5,200,771	5,214,448	5,227,560	5,116,102
381	Positive Meters	5,562,075	5,598,090	5,607,591	5,624,212	5,620,899	5,627,722	5,671,108	5,689,387	5,708,339	5,728,994	5,745,669	5,788,082	5,664,347
383	Service Regulators	798,833	798,471	806,893	815,125	815,527	815,622	818,350	820,702	820,141	819,727	820,591	821,741	814,310
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
386.2	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	$29,026,865	$29,108,570	$29,164,459	$29,218,580	$29,326,046	$29,551,897	$29,751,819	$29,815,085	$29,880,398	$29,931,353	$29,974,208	$30,046,040	$29,566,276
	General Plant													
389	Land	$105,845	$105,845	$105,845	$105,845	$105,845	$105,845	$105,849	$105,695	$339,877	$574,837	$575,457	$578,767	$242,963
390	Structures and Improvements	633,712	633,712	633,712	633,712	633,712	633,712	633,732	633,752	2,207,526	3,782,841	3,784,383	3,785,282	1,552,482
391.1	Furniture & Fixtures	222,883	222,883	222,883	219,025	215,167	215,167	215,176	215,185	215,185	215,185	289,261	363,336	235,945
391.3	Computer Equip.-PC	204,661	206,070	209,472	213,048	212,719	212,216	212,253	212,289	212,289	212,289	212,289	212,289	210,990
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
392.2	Transportation Equip, Unitized	1,455,469	1,457,790	1,460,103	1,487,796	1,499,448	1,493,719	1,484,304	1,470,074	1,486,134	1,496,698	1,524,090	1,574,300	1,490,827
393	Stores Equipment	29,501	40,161	50,821	50,821	50,821	50,821	50,821	50,821	53,771	56,721	56,721	56,721	49,877
394.1	Tools,Shop&Gar. Equip.-Non-Un.	449,833	454,530	459,228	461,018	462,808	464,841	466,194	465,514	465,893	466,272	489,032	511,792	468,080
394.2	Tools,Shop&Gar. Equip.-Unitized	73,712	65,794	57,875	57,875	57,875	57,875	57,875	57,875	57,875	57,875	57,875	57,875	59,855
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	138,079	138,079	138,079	138,079	138,079
395	Laboratory Equipment	42,911	42,911	42,911	42,911	42,911	42,911	42,929	42,947	42,947	42,947	42,947	42,947	42,928
396.1	Power Operated Equip.	82,045	86,267	90,490	88,116	85,741	85,741	85,741	85,741	85,741	85,741	85,741	85,741	86,071
396.2	Work Equipment Trailers	1,147,411	1,136,459	1,122,373	1,130,438	1,141,637	1,141,637	1,141,734	1,141,832	1,135,298	1,123,274	1,124,908	1,132,031	1,134,919
397.1	Radio Comm. Equip.-Fixed	86,556	86,556	86,556	86,556	86,556	86,556	86,556	86,556	86,556	86,556	86,556	86,556	86,556
397.2	Radio Comm. Equip.-Mobile	116,726	116,726	116,726	116,726	116,726	116,726	116,726	116,726	116,726	116,726	116,726	116,726	116,726
397.3	General Tele. Comm. Equip.	40,478	40,478	40,478	38,362	36,246	36,246	36,246	36,246	42,009	47,773	47,773	47,773	40,842
397.5	Supervisory & Tele. Equip.	84,774	84,774	84,774	84,774	84,774	84,774	84,777	84,779	84,779	84,779	84,779	84,779	84,776
397.6	Scada System	770	770	770	770	770	770	770	770	770	770	770	770	770
397.8	Network Equipment	14,381	17,281	17,637	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,602
398	Miscellaneous Equipment	33,276	33,276	33,276	33,276	33,276	33,276	33,277	33,279	33,279	33,279	33,279	33,279	33,277
	Total General Plant	$5,006,509	$5,013,848	$5,017,495	$5,050,625	$5,066,588	$5,062,389	$5,054,516	$5,039,637	$6,866,211	$8,684,119	$8,812,143	$8,970,520	$6,137,051
303	Intangible Plant - General	$139,667	$139,667	$139,667	$139,667	$139,667	$139,667	$139,728	$139,789	$137,434	$135,079	$135,079	$135,079	$138,349

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MONTANA-DAKOTA UTILITIES CO.
AVERAGE ALLOCATED GAS PLANT IN SERVICE BALANCES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

cct. No.	Account	July Average	August Average	September Average	October Average	November Average	December Average	January Average	February Average	March Average	April Average	May Average	June Average	12 Months Average
	Common Plant													
39	Land	$34,150	$28,637	$28,637	$28,637	$28,637	$28,637	$30,032	$31,426	$31,426	$31,426	$31,426	$31,426	$30,375
90	Structures and Improvements	435,496	330,925	333,891	333,971	333,836	334,680	352,024	368,390	368,390	368,633	371,311	373,344	358,741
91.1	Furniture & Fixtures	166,187	141,206	141,288	141,775	142,052	141,874	148,719	155,591	155,673	156,150	156,489	156,505	150,292
91.2	Computer Equipment-Bull/AS400	6,077	6,077	6,077	6,077	6,077	6,077	6,374	6,671	6,671	6,671	6,671	6,671	6,349
91.3	Computer Equip.-PC	214,960	193,834	195,023	197,024	198,912	197,850	206,507	218,295	224,889	231,900	235,441	238,357	212,749
91.5	Computer Equip.-Other	53,209	53,100	53,100	53,100	53,100	53,100	55,691	58,283	58,283	58,283	58,283	58,283	55,485
92.1	*Trans. Equip., Non-Unitized*	1,154	1,154	1,154	1,154	1,154	1,154	1,210	1,265	1,265	1,265	1,265	1,265	1,205
92.2	Trans. Equip., Unitized	45,465	41,994	40,326	42,044	42,631	42,632	44,265	46,180	46,469	46,492	47,773	49,065	44,611
92.3	Aircraft	66,657	66,657	66,657	66,657	66,657	66,657	69,911	73,164	73,164	73,164	75,180	77,196	70,143
93	Stores Equip.	258	258	258	258	258	258	270	283	283	283	283	283	269
94.1	Tools, Shop and Garage Equip.	1,816	1,816	1,816	1,816	1,816	1,816	1,905	1,994	1,994	1,994	1,994	1,994	1,898
94.3	Vehicle Maint. Equip.	5,541	5,565	5,565	5,565	5,565	5,565	5,834	6,103	6,103	6,103	6,103	6,103	5,810
94.4	Vehicle Refueling Equip.	5,706	6,014	6,321	6,321	6,321	6,282	6,545	6,848	6,848	6,848	6,848	6,848	6,479
96.2	*Work Equipment Trailers*	3,372	3,372	3,372	3,372	3,372	4,069	4,997	5,227	5,227	5,227	6,694	8,160	4,705
97.1	Radio Comm. Equip.-Fixed	12,353	12,353	12,353	12,353	12,353	12,353	12,956	13,559	13,559	13,559	13,559	13,559	12,906
97.2	Radio Comm. Equip.-Mobile	16,465	16,465	16,465	16,465	16,465	16,465	17,268	18,072	18,072	18,072	18,072	18,072	17,202
97.3	General Tele. Comm. Equip.	27,315	26,361	26,361	26,361	26,270	26,251	27,608	28,913	28,933	28,933	28,933	28,933	27,598
97.5	Supervisory and Telemetering Equip.	142	142	142	142	142	142	149	156	156	156	156	156	148
97.8	Network Equipment	49,526	43,950	43,926	43,926	43,931	46,623	51,862	54,628	54,877	55,086	55,285	55,222	49,904
98	Miscellaneous Equipment	29,073	25,148	25,148	25,262	25,350	25,400	26,725	28,024	28,310	28,548	28,548	29,344	27,073
	Total Common Plant	1,174,922	1,005,028	1,007,880	1,012,280	1,014,899	1,017,885	1,070,852	1,123,072	1,130,592	1,138,793	1,150,314	1,160,786	1,083,942
03	*Intangible Plant - Common*	$943,879	$940,396	$940,396	$940,396	$940,396	$948,042	$1,002,021	$1,048,355	$1,050,226	$1,054,370	$1,056,643	$1,058,215	$993,611
	Total Gas Plant in Service	$36,291,842	$36,207,509	$36,269,897	$36,361,548	$36,487,596	$36,719,880	$37,018,936	$37,165,938	$39,064,861	$40,943,714	$41,128,387	$41,370,640	$37,919,229

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MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2001

Work Order #	Description	Location	Construction Period	Date Placed In-Service	Beginning Balance	Major Additions	Major Retirements	Ending Balance
	Gas Plant				$162,825,108			
J103818	Relocate Main - Billings	MT	6/00-11/00	11/20/00		$100,948		
J104363	Extend mian - Big Horn	WY	6/00-12/00	12/29/00		284,891		
	Major projects Subtotal				162,825,108	385,839	0	
	Miscellaneous Projects					7,061,878	2,798,691	
	Subtotal				162,825,108	7,447,717	2,798,691	167,474,134
	Common Plant Allocated to Gas				17,377,141			19,061,313
	Total Gas Plant				$180,202,249			$186,535,447

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MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2000

Work Order #	Description	Location	Construction Period	Date Placed In-Service	Beginning Balance	Major Additions	Major Retirements	Ending Balance
	Gas Plant				$157,345,744			
	Major projects Subtotal				157,345,744	0	0	
	Miscellaneous Projects					7,626,806	2,147,442	
	Subtotal				157,345,744	7,626,806	2,147,442	162,825,108
	Common Plant Allocated to Gas				16,035,724			17,377,141
	Total Gas Plant				$173,381,468			$180,202,249

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MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
FOR THE TWELVE MONTHS ENDED JUNE 30, 1999

Work Order #	Description	Location	Construction Period	Date Placed In-Service	Beginning Balance	Major Additions	Major Retirements	Ending Balance
	Gas Plant				$152,419,287			
J50242	Replace Low Pressure Main - Spearfish	SD	5/98-11/98	11/23/98		$149,850		
J50487	Replace Low Pressure Main - Billings	MT	6/98-12/98	12/7/98		222,353		
J73955	Replace Main - Rapid City	SD	3/98-12/98	12/22/98		124,392		
	Major projects Subtotal				152,419,287	496,595	0	
	Miscellaneous Projects					7,219,298	2,789,436	
	Subtotal				152,419,287	7,715,893	2,789,436	157,345,744
	Common Plant Allocated to Gas				16,119,615			16,035,723
	Total Gas Plant				$168,538,902			$173,381,467

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MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
FOR THE TWELVE MONTHS ENDED JUNE 30, 1998

Work Order #	Description	Location	Construction Period	Date Placed In-Service	Beginning Balance	Major Additions	Major Retirements	Ending Balance
	Gas Plant				$147,576,183			
J50237	Replace Low Pressure Main - Spearfish	SD	5/97-10/97	10/17/97		$162,596		
J50365	Replace Low Pressure Main - Bismarck	ND	7/97-12-97	12/23/97		281,694		
J50487	Replace Low Pressure Main - Billings	MT	6/98	6/30/98		176,246		
J83031	Retire Flextrack plow	ND	11/98	11/30/98			109,764	
	Major projects Subtotal				147,576,183	620,536	109,764	
	Miscellaneous Projects					5,644,760	1,312,428	
	Subtotal				147,576,183	6,265,296	1,422,192	152,419,287
	Common Plant Allocated to Gas				15,044,319			16,119,615
	Total Gas Plant				$162,620,502			$168,538,902

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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 JUNE 30, 2002

None.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

	6/30/02	Projected 2002	Projected 2003
Distribution	$19,632,677	$20,213,217	$21,507,856
General	2,256,456	2,277,485	1,981,834
Intangible General	132,568	133,117	131,994
Common	494,061	472,963	470,124
Intangible Common	362,262	409,004	539,972
Total	$22,878,024	$23,505,786	$24,631,780

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2002

	12/31/01 Acc. Reserve for Depr.	6/30/02 Acc. Reserve for Depr.	2002 Average Plant In Service	Depreciation/ Amortization Rate 1/	2002 Depreciation/ Amortization Expense 2/	2002 Retirements/ Removal 2/	2002 Ending Balance	2002 Average Balance
Distribution	$19,581,089	$20,213,270	$30,449,566	4.53%	$689,683	($57,608)	$20,845,345	$20,213,217
General								
Other	1,138,591	830,012	4,129,420	3.36%	69,374	(90,554)	808,832	973,712
Clearing Accounts	1,397,313	1,270,409	2,942,790	5.33%	78,425	(138,602)	1,210,232	1,303,773
Intangible	134,761	130,945	137,373	0.77%	529	0	131,474	133,117
Total General	2,670,665	2,231,366	7,209,583		148,328	(229,156)	2,150,538	2,410,602
Common								
Other	421,936	469,156	1,002,420	5.58%	27,968	(56,651)	440,473	431,204
Clearing Accounts	33,977	48,572	124,694	10.96%	6,833	(5,865)	49,540	41,759
Intangible	339,238	427,377	1,082,049	10.21%	55,239	(3,846)	478,770	409,004
Total Common	795,151	945,105	2,209,163		90,040	(66,362)	968,783	881,967
Total Gas Plant in Service	$23,046,905	$23,389,741	$39,868,312		$928,051	($353,126)	$23,964,666	$23,505,786
Depreciation Expense					$842,793			

1/ Composite depreciation rates by function.
2/ Reflects July - December 2002 amount.

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MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2003

	2002 Acc. Reserve for Depr.	2003 Average Plant In Service	Depreciation/ Amortization Rate 1/	2003 Depreciation/ Amortization Expense	2003 Retirements/ Removal	2003 Ending Balance	2003 Average Balance
Distribution 2/	$20,845,345	$31,872,837	4.53%	$1,443,840	($118,818)	$22,170,367	$21,507,856
General							
Other	808,832	5,923,623	3.36%	199,034	(176,487)	831,379	820,106
Clearing Accounts	1,210,232	3,134,447	5.33%	167,066	(264,073)	1,113,225	1,161,728
Intangible	131,474	135,079	0.77%	1,040	0	132,514	131,994
Total General	2,150,538	9,193,149		367,140	(440,560)	2,077,118	2,113,828
Common							
Other	440,473	1,122,549	5.58%	62,638	(106,374)	396,737	418,605
Clearing Accounts	49,540	260,999	6.10%	15,921	(11,964)	53,497	51,519
Intangible	478,770	1,283,276	10.21%	131,022	(8,618)	601,174	539,972
Total Common	968,783	2,666,824		209,581	(126,956)	1,051,408	1,010,096
Total Gas Plant in Service	$23,964,666	$43,732,810		$2,020,561	($686,334)	$25,298,893	$24,631,780
Depreciation Expense				$1,837,574			

1/ Composite depreciation rates by function.

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MONTANA-DAKOTA UTILITIES CO.
MONTHLY ACCUMULATED PROVISIONS FOR DEPRECIATION BY FUNCTION
GAS UTILITY
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

	2001							2002					
Function	June	July	August	September	October	November	December	January	February	March	April	May	June
Distribution	$96,223,584	$96,708,948	$97,183,348	$97,661,889	$98,136,028	$98,207,316	$98,766,449	$99,215,679	$99,762,259	$100,315,693	$100,857,462	$101,396,892	$101,962,771
General	8,858,822	8,928,682	8,881,525	8,930,459	8,901,989	8,932,754	9,007,088	8,967,368	9,046,808	8,532,292	8,610,616	8,589,624	8,660,046
Total	$105,082,406	$105,637,630	$106,064,873	$106,592,348	$107,038,017	$107,140,070	$107,773,537	$108,183,047	$108,809,067	$108,847,985	$109,468,078	$109,986,516	$110,622,817

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN ACCUMULATED PROVISION FOR
DEPRECIATION AND AMORTIZATION - GAS UTILITY
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Gas Utility	Beginning Balance 7/1/01	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 6/30/02
Account 111.2 - Intangible	$432,233	$10,456					$442,689
Account 108							
Distribution	96,238,641	6,719,036	$635,838	$21,973	$373,297	($649)	101,971,164
General	9,050,383	909,692	1,677,368	832,252	4,415	446,502	8,664,042
Total Account 108	105,289,024	7,628,728	2,313,206	854,225	377,712	445,853	$110,635,206
Total Accounts 111.2 & 108	$105,721,257	$7,639,184	$2,313,206	$854,225	$377,712	$445,853	$111,077,895
Common 1/	$7,381,726						$8,522,258

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 June 30, 2002 are:

Common Utility	Beginning Balance 7/1/01	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 6/30/02
Account 111.0	$4,416,491	$1,399,154	$107,051	$4,023	$0	$0	$5,712,617
Account 108	18,710,152	1,968,334	5,828,039	4,668,496	25,739	4,494	19,488,710
Total Accounts 111.0 and 108	$23,126,643	$3,367,488	$5,935,090	$4,672,519	$25,739	$4,494	$25,201,327

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MONTANA-DAKOTA UTILITIES CO.
PROCEDURES FOLLOWED IN DEPRECIATING OR AMORTIZING PLANT AND RECORDING ABANDONMENT

There has been no policy change with respect to the methodology employed or procedures followed in depreciating and amortizing plant investments and recording plant abandonments since the end of the year reported in the Company's last FERC Form 1.

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 JUNE 30, 2002
PROJECTED 2002 - 2003

Working Capital	Average Balance @ 6/30/02	Projected 2002	Projected 2003
Materials and Supplies	$290,358	$253,531	$253,531
Prepaid Insurance	50,818	48,803	55,121
Unamortized FAS 106	174,495	166,563	150,699
Total Working Capital	$515,671	$468,897	$459,351
Customer Advances for Construction	$124,337	$90,063	$81,227

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
BY PRINCIPAL ITEM OF MAIN ACCOUNT
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Description	06/30/01	06/30/02	Average
Natural Gas Material	$281,139	$297,585	$289,362
Transportation Material	607	3,539	2,073
All Other Gas Material	1,379	(34)	673
Reserve for Inventory Shrinkage	(2,044)	(1,455)	(1,750)
Total	$281,081	$299,635	$290,358

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002 - 2003

	Per Books	Projected	
	6/30/02	2002 1/	2003
June 2001	$281,081		
July	266,912		
August	291,248		
September	265,291		
October	274,796		
November	227,342		
December	215,239	$215,239	
January 2002	203,557	203,557	
February	202,311	202,311	
March	249,521	249,521	
April	243,926	243,926	
May	243,876	243,876	
June	299,635	299,635	
July		308,209	
August		319,475	
September		292,780	
October		274,796	
November		227,342	
December		215,239	
Average Balance	$290,358		
Thirteen Month Average		$253,531	$253,531

1/ Reflects actual data through September 2002. October - December 2002 projected to remain at the 2001 level.

MONTANA-DAKOTA UTILITIES CO.
PREPAID INSURANCE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002 - 2003

	Per Books	Projected	
	6/30/2002	2002 1/	2003
June 2001	$45,645		
July	39,398		
August	39,450		
September	33,019		
October	25,306		
November	19,119		
December	11,361	$11,361	$12,303
January 2002	92,476	92,476	113,206
February	89,871	89,871	102,909
March	80,660	80,660	92,612
April	70,227	70,227	82,315
May	65,613	65,613	72,131
June	55,991	55,991	61,834
July		46,368	51,537
August		36,794	41,240
September		30,224	30,943
October		20,187	20,646
November		22,368	22,595
December		12,303	12,298
Average Balance	$50,818		
Thirteen Month Average		$48,803	$55,121

1/ Reflects actual data through September 2002. October 2002 - December 2003 based on insurance expense.

MONTANA-DAKOTA UTILITIES CO.
UNAMORTIZED FAS 106
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002 - 2003

	Per Books	Projected	
	6/30/2002	2002 1/	2003 1/
June 2001	$182,426		
July	181,104		
August	179,782		
September	178,460		
October	177,138		
November	175,816		
December	174,494	$174,494	$158,631
January 2002	173,172	173,172	157,309
February	171,850	171,850	155,987
March	170,529	170,529	154,665
April	169,207	169,207	153,343
May	167,885	167,885	152,021
June	166,563	166,563	150,699
July		165,241	149,377
August		163,919	148,055
September		162,597	146,733
October		161,275	145,411
November		159,953	144,089
December		158,631	142,767
Average Balance	$174,495	$166,563	$150,699

1/ Reflects amortization of balance.

MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002 - 2003

		Projected	
	Per Books	2002 1/	2003
June 2001	$152,323		
July	69,907		
August	70,113		
September	70,148		
October	70,266		
November	71,651		
December	71,841	$71,841	$81,227
January 2002	95,255	95,255	81,227
February	95,595	95,595	81,227
March	95,813	95,813	81,227
April	95,976	95,976	81,227
May	96,188	96,188	81,227
June	96,351	96,351	81,227
July		99,367	81,227
August		99,530	81,227
September		81,227	81,227
October		81,227	81,227
November		81,227	81,227
December		81,227	81,227
Average Balance	$124,337		
Thirteen Month Average		$90,063	$81,227

1/ Reflects actual data through September 2002 and projected to remain at that level throughout 2002 and 2003.

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
GAS UTILITY - SOUTH DAKOTA
MONTHLY BALANCES FOR YEARS ENDED
JUNE 30, 2000 AND JUNE 30, 2001

	6/30/2000	6/30/2001
July	$283,272	$270,551
August	265,493	269,291
September	247,526	263,110
October	256,803	238,413
November	252,783	244,524
December	231,131	232,559
January	215,280	191,723
February	219,843	182,221
March	219,980	202,716
April	247,788	261,667
May	236,585	250,993
June	241,303	281,081

MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY
TWELVE MONTHS ENDING JUNE 30, 2002

Refer to Rule 20:10:13:69, Schedule F-1, page 5.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE CAPITAL STRUCTURE
JUNE 30, 2002

	Balance	Subsidiary Portion of Balance	Adjusted Balance	Capital Ratio	Cost	Required Return
Long Term Debt	$133,100,000		$133,100,000	43.997%	9.276%	4.081%
Preferred Stock	16,450,000		16,450,000	5.438%	4.630%	0.252%
Common Equity	1,092,829,612	939,861,190	152,968,422	50.565%	12.000%	6.068%
Total	$1,242,379,612	$939,861,190	$302,518,422	100.000%		10.401%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE CAPITAL STRUCTURE
PROJECTED 2002

	Utility Balance	Capital Ratio	Cost	Required Return
Long Term Debt	$133,100,000	43.708%	9.241%	4.039%
Preferred Stock	16,350,000	5.369%	4.626%	0.248%
Common Equity	155,067,950	50.923%	12.000%	6.111%
Total	$304,517,950	100.000%		10.398%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE CAPITAL STRUCTURE
PROJECTED 2003

	Adjusted Balance	Capital Ratio	Cost	Required Return
Long Term Debt	$145,100,000	44.674%	9.027%	4.033%
Preferred Stock	16,250,000	5.003%	4.622%	0.231%
Common Equity	163,446,692	50.323%	12.000%	6.039%
Total	$324,796,692	100.000%		10.303%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
JUNE 30, 2002

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
First Mortgage Bonds			
Balance at June 30, 2001	$130,850,000	$11,743,442	8.975%
Amortization of Gain/Loss		501,567	
		12,245,009	
Balance at June 30, 2002	130,850,000	$11,743,442	8.975%
Amortization of Gain/Loss		408,186	
		12,151,628	
Average at June 30, 2002	130,850,000	11,743,442	8.975%
Average Amort. of Gain/Loss		454,877	
	130,850,000	12,198,319	9.322%
Pollution Control Bonds			
Balance at June 30, 2001	2,500,000	163,900	6.556%
Balance at June 30, 2002	2,000,000	131,120	6.556%
Average at June 30, 2002	2,250,000	147,510	6.556%
Total Average Long Term Debt	$133,100,000	$12,345,829	9.276%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
PROJECTED 2002

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
First Mortgage Bonds			
Balance at December 31, 2001	$130,850,000	$11,743,442	8.975%
Amortization of Gain/Loss		454,705	
		12,198,147	
Balance at December 31, 2002	130,850,000	$11,743,442	8.975%
Amortization of Gain/Loss		361,666	
		12,105,108	
Average at December 31, 2002	130,850,000	11,743,442	8.975%
Average Amort. of Gain/Loss		408,186	
Total Average	130,850,000	12,151,628	9.287%
Pollution Control Bonds			
Balance at 12/31/01	2,500,000	163,900	6.556%
Balance at 12/31/02	2,000,000	131,120	6.556%
Average at 12/31/02	2,250,000	147,510	6.556%
Total Average Long Term Debt	$133,100,000	$12,299,138	9.241%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
PROJECTED 2003

	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
First Mortgage Bonds			
Balance at December 31, 2002	$130,850,000	$11,743,442	8.975%
Amortization of Gain/Loss		361,666	
		12,105,108	
Balance at December 31, 2003	155,850,000	$13,593,442	8.722%
Amortization of Gain/Loss		268,627	
		13,862,069	
Average at December 31, 2003	143,350,000	12,668,442	8.837%
Average Amort. of Gain/Loss		315,147	
Total Average	143,350,000	12,983,589	9.057%
Pollution Control Bonds			
Balance at December 31, 2002	2,000,000	131,120	6.556%
Balance at December 31, 2003	1,500,000	98,340	6.556%
Average at December 31, 2003	1,750,000	114,730	6.556%
Total Average Long Term Debt	$145,100,000	$13,098,319	9.027%

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
JUNE 30, 2002

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%
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%
				$136,450,000	$136,361,100	$892,750		$13,091,800	

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	
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	116,949,508			130,850,000	11,743,442	8.975%
Pollution Control Notes:						
Grant County 6.2%	5,427,042	96.911%	6.556%	2,000,000	131,120	6.556%
Total Long-Term Debt Capital	$122,376,550			$132,850,000	$11,874,562	8.938%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

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MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2002

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%
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%
				$136,450,000	$136,361,100	$892,750		$13,091,800	

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	
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	116,949,508			130,850,000	11,743,442	8.975%
Pollution Control Notes:						
Grant County 6.2%	5,427,042	96.911%	6.556%	2,000,000	131,120	6.556%
Total Long-Term Debt Capital	$122,376,550			$132,850,000	$11,874,562	8.938%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

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%
New Debt Issue:									
7.40% Projected issuance 2003.			7.400%	25,000,000	25,000,000	0	0.000%	0	0.000%
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%
				$161,450,000	$161,361,100	$892,750		$13,091,800	

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	
7.40%	25,000,000	100.000%	7.400%	25,000,000	1,850,000	
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	141,949,508			155,850,000	13,593,442	8.722%
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	$147,376,550			$157,350,000	$13,691,782	8.701%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

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MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
JUNE 30, 2002

		Projected Average Amortization
Acct. 1890 - Unamortized Loss		
9 1/8% due 05-15-06	7/00 - 6/01	$501,567
9 1/8% due 05-15-06	7/01 - 6/02	408,186
Average at June 30, 2002		$454,877

MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
PROJECTED 2002

		Projected Average Amortization
Acct. 1890 - Unamortized Loss		
9 1/8% due 05-15-06	1/01-12/01	$454,705
9 1/8% due 05-15-06	1/02-12/02	361,666
Average at December 31, 2002		$408,186

MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
PROJECTED 2003

		Projected Average Amortization
Acct. 1890 - Unamortized Loss		
9 1/8% due 05-15-06	1/02-12/02	$361,666
9 1/8% due 05-15-06	1/03-12/03	268,627
Average at December 31, 2003		$315,147

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
JUNE 30, 2002

Description	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
Balance - June 30, 2001	$16,500,000	$764,275	4.632%
Redemptions:			
5.1% Series	(100,000)	(5,285)	
Balance - June 30, 2002	$16,400,000	$758,990	4.628%
Average Preferred Stock	$16,450,000	$761,633	4.630%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
PROJECTED 2002

Description	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
Balance - December 31, 2001	$16,400,000	$758,990	4.628%
Redemptions:			
5.1% Series	(100,000)	(5,285)	
Balance - December 31, 2002	$16,300,000	$753,705	4.624%
Average Preferred Stock	$16,350,000	$756,348	4.626%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
PROJECTED 2003

Description	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
Balance - December 31, 2002	$16,300,000	$753,705	4.624%
Redemptions:			
5.1% Series	(100,000)	(5,285)	
Balance - December 31, 2003	$16,200,000	$748,420	4.620%
Average Preferred Stock	$16,250,000	$751,063	4.622%

MONTANA-DAKOTA UTILITIES CO.
PREFERRED STOCK CAPITAL
JUNE 30, 2002

Description	Date of Issuance	Call (Redemption) Price	Dividend Rate	Par Value of Issue	Gross Proceeds (000's)	Underwriters' Commission		Issuance Expense	
						Amount	% Gross Proceeds	Amount	% 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		Cost of Money 1/ 2/	Principal Outstanding	December 31, 2001		Method of Offering
	Amount (000's)	Per Unit			Annual Cost	Embedded Cost	
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%	1,400,000	73,990		Private
Total				$16,400,000	$758,990	4.628%	

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.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
JUNE 30, 2002

Description	Amount
Common Equity - June 30, 2001	$1,016,644,144
Unappropriated Retained Earnings of Subsidiaries	305,460,452
Additional Equity of Subsidiaries (Centennial)	558,808,351
Utility Common Equity - 6/30/01	$152,375,341
Common Equity - June 30, 2002	$1,169,015,079
Unappropriated Retained Earnings of Subsidiaries	368,251,110
Additional Equity of Subsidiaries (Centennial)	647,202,466
Utility Common Equity - June 30, 2002	153,561,503
Average Common Utility Equity - June 30, 2002	$152,968,422

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
PROJECTED 2002

Description	Amount
Common Equity - December 31, 2001	$1,111,178,402
Unappropriated Retained Earnings of Subsidiaries	353,291,342
Additional Equity of Subsidiaries (Centennial)	603,266,687
Utility Common Equity - December 31, 2001	$154,620,373
Projected Utility Earnings	19,062,190
Projected Utility Dividends	(16,485,400)
Projected Utility Adjustments	(1,681,637)
Utility Common Equity - December 31, 2002	155,515,526
Average Common Utility Equity - December 31, 2002	$155,067,950

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
PROJECTED 2003

Description	Amount
Utility Common Equity - December 31, 2002	$155,515,526
Projected Utility Earnings	16,506,331
Projected Utility Dividends	(17,012,000)
Equity Infusion	16,368,000
Utility Common Equity - December 31, 2003	171,377,857
Average Common Utility Equity - December 31, 2003	$163,446,692

MDU Resources Group Inc.
Equity Issuance - 1997- 2002

	DRIP			401-K			Acquisition			Equity Draw Down			Employee Stock Exer.			
eriod	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares Outstanding
eginning Balance																42,715,472
an-97	168,576	$2,549,705	16,858													42,884,048
eb-97	10,665	159,524.00	1,067													42,894,713
lar-97	14,479	206,342	1,448													42,909,192
pr-97	89,233	1,293,878	8,923	84,156	1,220,313	8,416										43,082,581
ay-97	14,049	215,409	1,405	13,800	230,000	1,380										43,110,430
un-97	9,716	159,079	972	1,378	22,458	138										43,121,524
Jul-97	78,264	1,258,732	7,826	99,305	1,597,097	9,931	338,444	4,372,873	5,000							43,637,537
ug-97	13,374	123,041	1,337	44,628	718,435	4,463										43,695,539
ep-97	7,904	126,598	790	11,555	187,520	1,156										43,714,998
ct-97																43,714,998
ov-97																43,714,998
ec-97																43,714,998
an-98																43,714,998
eb-98																43,714,998
lar-98							5,772,526	90,139,102	5,000							49,487,524
pr-98							818,318	12,778,193	5,000	1,303,602	45,163,291	2,408,000	(3)			51,609,444
ay-98																51,609,444
un-98																51,609,444
Jul-98							1,474,855	23,030,144	5,000							53,084,299
ug-98							23,038	359,743	5,000							53,107,337
ep-98							29,428	459,524	5,000							53,136,765
ct-98	55,473	1,437,087	5,547	48,823	1,264,803	4,882	15,141	236,430	5,000							53,256,202
ov-98	8,814	237,430	881													53,265,016
ec-98	7,935	205,568	794													53,272,951
an-99	56,114	1,497,514	5,611	47,760	1,274,595	4,776										53,376,825
eb-99	9,172	214,150	917													53,385,997
ar-99	9,528	219,744	953													53,395,525
pr-99																53,395,525
ay-99																53,395,525
un-99							898,103	17,927,591	5,000							54,293,628
ul-99																54,293,628
ug-99							516,661	10,313,391	5,000							54,810,289
ep-99							2,094,515	41,809,913	5,000							56,904,804
ct-99																56,904,804
ov-99							373,111	7,447,898	5,000							57,277,915
ec-99																57,277,915
an-00							18,252	320,593	5,000							57,296,167
eb-00																57,296,167
ar-00																57,296,167
or-00							1,266,037	22,237,687	5,000							58,562,204
ay-00							2,826,087	49,639,653	5,000							61,388,291
un-00							131,457	2,309,016	5,000							61,519,748
ul-00							1,203,856	21,145,490	5,000	221,778	4,753,939	118,848				62,945,382
ug-00							563,819	9,903,368	5,000	242,822	5,445,825	136,146				63,752,023
ep-00										714,378	17,078,277	426,957				64,466,401
ct-00							10,427	183,148	5,000	197,619	5,454,667	136,367				64,674,447
ov-00										246,532	6,899,491	172,487				64,920,979
ec-00							83,168	1,460,862	5,000	263,420	7,616,272	190,407				65,267,567

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MDU Resources Group Inc.
Equity Issuance - 1997- 2002

	DRIP			401-K			Acquisition			Equity Draw Down			Employee Stock Exer.			
Period	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares Outstanding
an-01							168,402	5,294,146	5,000							65,435,969
eb-01										528,787	14,999,974	374,999				65,964,756
lar-01							96,326	3,028,253	5,000	358,429	10,000,000	250,000	21,814	451,768	-	66,441,325
pr-01							1,651,486	51,918,667	5,000				62,252	1,289,239	-	68,155,063
lay-01													21,100	436,981	-	68,176,163
un-01							93,750	2,947,270	5,000				3,300	68,343	-	68,273,213
Jul-01													3,000	62,130	-	68,276,213
ug-01													3,550	73,521	-	68,279,763
ep-01										1,105,353	25,000,000	625,000	1,200	24,852	-	69,386,316
ct-01													684	14,166	-	69,387,000
ov-01													900	18,639	-	69,387,900
ec-01							58,816	1,849,031	5,000	569,065	15,000,000	375,000	1,070	22,160	-	70,016,851
an-02													980	20,296	-	70,017,831
eb-02							94,252	2,508,078	5,000				1,950	40,385	-	70,114,033
lar-02							501,578	13,347,164	5,000				1,227	25,411	-	70,616,838
pr-02							466,667	12,418,170	5,000				3,218	69,091	-	71,086,723
ay-02							89,161	2,372,605	5,000				1,050	21,746	-	71,176,934
un-02							487,367	12,969,004	5,000				450	9,320	-	71,664,751
tals	553,296	$9,903,801	$55,330	351,405	$6,515,221	$35,141	22,165,048	$424,727,007	$145,000	5,751,785	$157,411,736	$5,214,211	127,745	$2,648,048		
			(1)			(1)			(2)			(4)				

otnotes:
Assumed to be $.10 per share.
Estimated Legal & Administrative costs of $5,000 per transaction.
$2,058,000 underwriters discount plus $350,000 other expenses (legal, administrative, etc.).
Underwriters discount estimated at 2.5 percent of market based on negotiated average price at draw-down.

MDU RESOURCES GROUP, INC.
STOCK DIVIDENDS, STOCK SPLITS OR CHANGES IN PAR OR STATED VALUE
FOR THE FIVE-YEAR PERIOD ENDING JUNE 30, 2002

On June 30, 1998, MDU Resources Group, Inc. issued 17,203,148 additional shares of Common Stock, Par value $3.33, in connection with a three-for-two Common Stock split to be effected in the form of a fifty percent stock dividend.

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 that the company is authorized to issue from 75,000,000 shares of common stock with a par value of $3.33 to 150,000,00 shares with a par value of $1.00.

MDU RESOURCES GROUP, INC.
COMMON STOCK DATA
FOR THE FIVE YEARS ENDED DECEMBER 31, 2001 AND TWELVE MONTHS ENDED JUNE 30, 2002

	Avg. Number of Shares Outstanding (000's)	Annual Earnings (per share)	Annual Dividends (per share)	Dividend/ Earnings Ratio	Average Market Price 1/	Price/ Earnings Ratio	Dividend/ Price Ratio
Year Ended December 31:							
1997	43,478	1.24	0.75	61%	16.62	13.4	4.5%
1998	50,837	0.66 2/	0.78	119%	23.82	36.1	3.3%
1999	54,870	1.52	0.82	54%	22.90	15.1	3.6%
2000	61,390	1.80	0.86	48%	24.03	13.4	3.6%
2001	67,869	2.29	0.90	39%	30.25	13.2	3.0%
Year Ended June 30:							
2002	69,576	1.83	0.92	50%	27.95	15.3	3.3%
Twelve Months:							
July, 2001	66,008	2.37	0.88	37%	30.45	12.8	2.9%
August	66,489	2.42	0.89	37%	29.90	12.4	3.0%
September	66,824	2.43	0.89	37%	25.54	10.5	3.5%
October	67,199	2.40	0.89	37%	24.88	10.4	3.6%
November	67,529	2.38	0.90	38%	24.83	10.4	3.6%
December	67,869	2.29	0.90	39%	26.25	11.5	3.4%
January, 2002	68,237	2.34	0.90	38%	27.88	11.9	3.2%
February	68,539	2.21	0.91	41%	28.33	12.8	3.2%
March	68,877	2.12	0.91	43%	29.97	14.1	3.0%
April	69,114	2.04	0.91	45%	30.95	15.2	2.9%
May	69,307	1.87	0.92	49%	29.29	15.7	3.1%
June	69,576	1.83	0.92	50%	27.95	15.3	3.3%

1/ This average market price is based on monthly high and low for the year.
2/ Reflects $39.9 million or 78 cents per common share in noncash after-tax write-down of natural gas and oil properties.

MDU RESOURCES GROUP, INC.
REACQUISITION OF BONDS OR PREFERRED STOCK
FOR THE FIVE-YEAR PERIOD ENDING JUNE 30, 2002

First Mortgage Bonds

$20,000,000, 9 1/8% Series, First Mortgage Bonds were reacquired during May 1998. A call premium of 4.45% or $890,000 was paid on redemption.

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
TWELVE MONTHS ENDED JUNE 30, 2002

Acct. No.	Total Company	South Dakota
Cost of Gas	$106,488,405	$21,351,949
Other Gas Supply	421,075	64,321
Distribution	12,339,089	2,674,890
Customer Accounts	6,310,458	1,243,204
Customer Service & Info.	316,774	63,686
Sales	1,246,172	252,371
Administrative and General	10,259,442	1,964,267
Total Operation and Maintenance Expense	$137,381,415	$27,614,688

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002

Acct. No.		Total Company	South Dakota
	Other Gas Supply Expenses		
804	Natural Gas City Gate Purch.	$118,096,365	$24,795,740
805	Other Gas Purchases	5,112,858	780,558
808.1	Gas Withdrawn from Storage	22,059,574	4,133,053
808.2	Gas Delivered to Storage	(38,780,392)	(8,357,402)
813	Other Gas Supply Expenses	421,075	64,321
	Total Other Gas Supply Expenses	$106,909,480	$21,416,270
	Distribution Expenses		
	Operation		
870	Supervision & Engineering	$1,381,408	$391,213
871	Distribution Load Dispatching	166,624	31,454
874	Mains and Service	2,529,533	722,091
875	Measuring & Reg. Station Exp.-General	69,656	5,970
876	Measuring & Reg. Station Exp.-Ind.	46,328	5,896
877	Measuring & Reg. Station Exp. - CG	36,826	48
878	Meters & House Regulators	1,156,636	240,930
879	Customer Installations	2,167,994	435,155
880	Other Expenses	2,893,120	529,606
881	Rents	85,431	32,909
	Total Operation Expenses	10,533,556	2,395,272
	Maintenance		
885	Supervision & Engineering	559,318	66,327
886	Structures & Imp.	5,678	2,349
887	Mains	272,846	55,967
889	Measuring & Reg. Station Exp.-General	45,646	6,203
890	Mtc of Meas & Reg Stn Eq - Ind.	11,424	4,624
891	Mtc of Meas & Reg Stn Eq - CG	4,373	0
892	Services	268,823	29,333
893	Meters & House Regulators	212,161	42,708
894	Other Equipment	425,264	72,107
	Total Maintenance Expenses	1,805,533	279,618
	Total Distribution Expenses	$12,339,089	$2,674,890
	Customer Accounts Expenses		
901	Supervision	$512,463	$80,928
902	Meter Reading Expenses	1,409,999	263,402
903	Customer Records and Collection Exp.	3,668,404	724,755
904	Uncollectible Accounts	322,303	81,448
905	Misc. Customer Accounts Expenses	397,289	92,671
	Total Customer Accounts Expenses	$6,310,458	$1,243,204

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002

Acct. No.		Total Company	South Dakota
	Customer Service & Information Exp.		
907	Supervision	$34,389	$2,456
908	Customer Assistance Expenses	199,994	45,516
909	Informational & Instructional Advertising Expenses	76,925	15,673
910	Misc. Customer Service & Info. Expenses	5,466	41
	Total Customer Service & Info. Expenses	$316,774	$63,686
	Sales Expenses		
	Operation		
911	Supervision	$284,712	$46,509
912	Demonstrating & Selling Expenses	789,822	167,622
913	Advertising Expenses	95,330	21,856
916	Miscellaneous Sales Expenses	76,308	16,384
	Total Sales Expenses	$1,246,172	$252,371
	Administrative & General Expenses		
	Operation		
920	Administrative & General Salaries	$3,049,389	$611,440
921	Office Supplies & Expenses	1,717,519	342,189
923	Outside Services Employed	423,625	78,360
924	Property Insurance	391,444	78,807
925	Injuries & Damages	400,597	87,073
926	Employee Pensions & Benefits	2,741,723	514,641
927	Franchise Requirements	39	0
928	Regulatory Commission Expenses	28,619	59
930.1	General Advertising Expense	161,195	17,441
930.2	Miscellaneous General Expenses	474,876	108,085
931	Rents	284,314	25,271
	Total Operation Expenses	9,673,340	1,863,366
	Maintenance		
935	Maintenance of General Plant	586,102	100,901
	Total Administrative & General Expenses	$10,259,442	$1,964,267
	Total Operation & Maintenance Expenses	$137,381,415	$27,614,688

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2002

Function	Total	Cost of Gas	Labor	Benefits	Insurance	Advertising	Postage	Industry Dues	Rate Case	All Other O&M
Cost of Gas	$26,720,886	$26,720,886								$0
Other Gas Supply	67,254		$58,951							8,303
Distribution	2,786,255		1,922,230				$5,679			858,346
Customer Accounts	1,299,255		855,568				115,656			328,031
Customer Service & Information	65,787		39,669			$15,673				10,445
Sales	240,793		198,386				682			41,725
Administrative and General	2,212,855		692,792	598,858	135,152	17,200	14,301	$44,285	$17,898	692,369
Total Other O&M	6,672,199	0	3,767,596	598,858	135,152	32,873	136,318	44,285	17,898	1,939,219
Total O&M	$33,393,085	$26,720,886	$3,767,596	$598,858	$135,152	$32,873	$136,318	$44,285	$17,898	$1,939,219

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MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2003

Function	Total	Cost of Gas	Labor	Benefits	Insurance	Advertising	Postage	Industry Dues	Rate Case	All Other O&M
Cost of Gas	$26,946,077	$26,946,077								
Other Gas Supply	71,993		$63,467							$8,526
Distribution	2,956,502		2,069,473				$5,679			881,350
Customer Accounts	1,373,583		921,105				115,656			336,822
Customer Service & Information	69,106		42,708			$15,673				10,725
Sales	257,107		213,582				682			42,843
Administrative and General	2,564,518		745,860	840,945	173,105	17,200	14,301	$44,285	$17,898	710,924
Total Other O&M	7,292,809	0	4,056,195	840,945	173,105	32,873	136,318	44,285	17,898	1,991,190
Total O&M	$34,238,886	$26,946,077	$4,056,195	$840,945	$173,105	$32,873	$136,318	$44,285	$17,898	$1,991,190

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MONTANA-DAKOTA UTILITIES CO.
COST OF GAS
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2002-2003

	Projected Dk Sales	Dk Adjusted for Distribution Losses 1/	Commodity Charge 2/	Projected Cost of Gas
Projected 2002				
Residential	3,119,384	3,146,443	$4.2250	$13,293,722
Firm General Service	2,129,961	2,148,438	4.2250	9,077,151
Merillat	625,741	631,169	3.5104 3/	2,215,656
Air Force 4/	569,719	569,719	3.0130	1,716,563
Small Interruptible	38,760	39,096	4.2250	165,181
Large Interruptible	83,120	83,841	3.0130	252,613
Total	6,566,685	6,618,706		$26,720,886
Projected 2003				
Residential	3,151,151	3,178,486	$4.2250	$13,429,103
Firm General Service	2,151,036	2,169,695	4.2250	9,166,961
Merillat	625,741	631,169	3.5104 3/	2,215,656
Air Force 4/	569,719	569,719	3.0130	1,716,563
Small Interruptible	38,760	39,096	4.2250	165,181
Large Interruptible	83,120	83,841	3.0130	252,613
Total	6,619,527	6,672,006		$26,946,077

1/ Distribution loss factor of .86%.
2/ Exhibit B, Purchased Gas Cost Adjustment effective December 1, 2002.
3/ Pursuant to contract with Merillat.
4/ The Air Force owns its distribution system so there are no distibution losses.

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO LABOR EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

	6/30/02 Per Books		Projected	
Function	Gas Utility	South Dakota 1/	2002 2/	2003 3/
Other Gas Supply	$290,543	$56,235	$58,951	$63,467
Distribution	9,626,800	1,833,664	1,922,230	2,069,473
Customer Accounts	4,278,695	816,148	855,568	921,105
Customer Service & Informa	472,877	37,841	39,669	42,708
Sales	625,587	189,245	198,386	213,582
Administrative and General	3,347,564	660,872	692,792	745,860
Total	$18,642,066	$3,594,005	$3,767,596	$4,056,195

1/ Directly assigned and allocated to South Dakota.
2/ Reflects 4.83% wage increase for the calendar year 2002.
3/ Reflects 7.66% increase for 2003.

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO BENEFITS EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

	6/30/02 Per Books		Projected 1/	
	Gas Utility	South Dakota	2002	2003
Medical/Dental	$2,014,274	$378,120	$359,781	$428,679
Pension	(1,430,653)	(273,717)	(262,276)	(111,389)
Post-Retirement	1,165,683	218,015	241,539	258,253
401-K	490,023	94,980	99,340	102,678
Workers Compensation	66,253	20,100	38,389	42,397
SISP			122,085	120,327
Total	$2,305,580	$437,498	$598,858	$840,945

1/ Each benefit adjusted individually.

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO INSURANCE EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

	6/30/02 Per Books		Projected	
	Gas Utility	South Dakota	2002 1/	2003 2/
Insurance Expense	$590,367	$118,405	$135,152	$173,105

1/ Reflects an increase of 14%.
2/ Reflects an increase of 28%.

MONTANA-DAKOTA UTILITIES CO.
POSTAGE EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING JUNE 30, 2002
PROJECTED 2002-2003

	Per Books		Projected 1/	
	Gas Utility	South Dakota	2002	2003
Distribution	$30,229	$5,283	$5,679	$5,679
Customer Accts.	583,447	107,587	115,656	115,656
Sales	7,259	634	682	682
A&G	66,346	13,303	14,301	14,301
Total Postage	$687,281	$126,807	$136,318	$136,318

1/ Increase of 7.5% to reflect annualized increase in postage effective June 30, 2002.

MONTANA-DAKOTA UTILITIES CO.
INDUSTRY DUES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	Per Books	2002	2003
American Gas Association 1/	$5,817	$7,711	$7,711
Rapid City Chamber of Commerce	6,575	6,575	6,575
Stugis Chamber of Commerce	574	574	574
Deadwood Chamber of Commerce	250	250	250
Belle Fourche Chamber of Commerce	499	499	499
Lead Area Chamber of Commerce	250	250	250
Northern Hills Community	250	250	250
Whitewood Chamber of Commerce	40	40	40
Montana Coal Council	200	200	200
Spearfish Economic	500	500	500
Rapic City Area Economic	3,500	3,500	3,500
Spearfish Chamber of Commerce	599	599	599
UTC	340	340	340
NARUC	179	179	179
Energy Safety Assoc.	1,060	1,060	1,060
Utility Shareholders of South Dakota	19,403	19,403	19,403
Other	2,355	2,355	2,355
Total	$42,391	$44,285	$44,285

1/ Reflects 2002 dues, adjusted to eliminate 2.01% for lobbying.

MONTANA-DAKOTA UTILITIES CO.
ADVERTISING EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING JUNE 30, 2002
PROJECTED 2002-2003

	Per Books		Projected	
	Gas Utility	South Dakota	2002	2003
Informational	$76,925	$15,673	$15,673	$15,673
Promotional	95,330	21,856		
Institutional	161,195	17,441	17,200	17,200
Total	$333,450	$54,970	$32,873	$32,873

MONTANA-DAKOTA UTILITIES CO.
REGULATORY COMMISSION EXPENSE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	Per Books	2002 1/	2003 1/
Regulatory Commission Expense	$59	$17,898	$17,898

1/ Reflects three year amortization of rate case expense.

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO OTHER O&M FOR INFLATION
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING JUNE 30, 2002
PROJECTED 2002-2003

		Projected 1/	
Function	Other O&M	2002	2003
Other Gas Supply	$8,086	$8,303	$8,526
Distribution	835,943	858,346	881,350
Customer Accounts	319,469	328,031	336,822
Customer Service & Informa	10,172	10,445	10,725
Sales	40,636	41,725	42,843
Administrative and General	674,298	692,369	710,924
Total Other O&M	$1,888,604	$1,939,219	$1,991,190

1/ Increase of 2.68% annually.

MONTANA-DAKOTA UTILITIES CO.
O&M ITEMS ADJUSTED INDIVIDUALLY
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002

Function	Per Books	Cost of Gas	Labor	Benefits	Insurance	Advertising	Postage	Industry Dues	Rate Case	All Other O&M
Cost of Gas	$21,351,949	($21,351,949)								$0
Other Gas Supply	64,321		($56,235)							8,086
Distribution	2,674,890		(1,833,664)				($5,283)			835,943
Customer Accounts	1,243,204		(816,148)				(107,587)			319,469
Customer Service & Information	63,686		(37,841)			($15,673)				10,172
Sales	252,371		(189,245)			(21,856)	(634)			40,636
Administrative and General	1,964,267		(660,872)	(437,498)	(118,405)	(17,441)	(13,303)	($42,391)	($59)	674,298
Total Other O&M	6,262,739	0	(3,594,005)	(437,498)	(118,405)	(54,970)	(126,807)	(42,391)	(59)	1,888,604
Total O&M	$27,614,688	($21,351,949)	($3,594,005)	($437,498)	($118,405)	($54,970)	($126,807)	($42,391)	($59)	$1,888,604

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS – GAS UTILITY
FOR THE TWELVE MONTHS ENDING JUNE 30, 2002

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 June 30, 2002.

MONTANA-DAKOTA UTILITIES CO.
ADVERTISING, BENEFITS AND
REGULATORY COMMISSION EXPENSE
GAS UTILITY
FOR THE TWELVE MONTHS ENDING JUNE 30, 2002

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 9 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 10 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

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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 JUNE 30, 2002

Williston Basin Interstate Pipeline Co.	$46,629,906
JTL Group Inc.	15,774
Empire Sand & Gravel Co	2,148
Fidelity Exploration & Production	7,815,578
Wagner-Smith Company	5,194
Highline Equipment Inc.	649
Wagner Smith Equipment Co	200
Total	$54,469,449

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2002-2003

	Per Books		Projected 2002		Projected 2003	
	Dk	Revenue	Dk	Revenue	Dk	Revenue
Sales						
Residential	3,015,866	16,986,636	3,119,384	$20,324,132	3,151,151	$20,560,052
Firm General	2,699,128	12,000,208	2,755,702	13,942,837	2,776,777	14,062,198
Air Force	573,249	1,346,470	569,719	1,753,026	569,719	1,753,026
Small Interruptible	42,145	170,207	38,760	188,950	38,760	188,950
Large Interruptible	88,681	215,412	83,120	269,779	83,120	269,779
Unbilled Revenue		174,682				
Total Sales	6,419,069	30,893,615	6,566,685	36,478,724	6,619,527	36,834,005
Transportation						
Small Interruptible	432,707	255,763	370,750	$208,592	364,450	$205,543
Large Interruptible	862,122	204,986	694,670	152,356	664,670	147,046
Unbilled Revenue		(7,084)				
Total Transportation	1,294,829	453,665	1,065,420	360,948	1,029,120	352,589
Total	7,713,898	$31,347,280	7,632,105	$36,839,672	7,648,647	$37,186,594

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MONTANA-DAKOTA UTILITIES CO.
MISCELLANEOUS REVENUES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDING JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	2001	2002	2003
Miscellaneous Service Revenue	$39,820	$39,820	$39,820
Rent from Property	84,274	84,274	84,274
Other Revenue	23,331	23,331	23,331
Total Misc. Revenues	$147,425	$147,425	$147,425

Montana-Dakota Utilities Co.
Gas Utility - South Dakota
Summary of Revenues
Twelve Months Ended June 30, 2002
Projected 2003

	Per Books		Per Books @ Current Rates 1/		Normalized 1/	
Rate Reporting Class	Dk	Revenue	Dk	Revenue	Dk	Revenue
Sales						
Residential						
Residential	3,015,866	$16,986,636	3,015,866	$19,734,185	3,090,609	$20,150,423
Total Residential	3,015,866	16,986,636	3,015,866	19,734,185	3,090,609	20,150,423
Air Force						
Interruptible	573,249	1,346,470	573,249	1,763,880	569,719	1,753,026
Total Air Force	573,249	1,346,470	573,249	1,763,880	569,719	1,753,026
Firm General						
Firm General	2,699,128	12,000,208	2,699,128	13,648,697	2,728,668	13,800,909
Total Firm General	2,699,128	12,000,208	2,699,128	13,648,697	2,728,668	13,800,909
Interruptible						
Small Interruptible	42,145	170,207	42,145	205,610	41,787	203,908
Large Interruptible	88,681	215,412	88,681	287,709	89,181	289,320
Total Interruptible	130,826	385,619	130,826	493,319	130,968	493,228
Total Sales	6,419,069	30,718,933	6,419,069	35,640,081	6,519,964	36,197,586
Transportation						
Small Interruptible	432,707	255,763	432,707	240,646	431,856	240,234
Large Interruptible	862,122	204,986	862,122	185,796	862,122	185,796
Total Transportation	1,294,829	460,749	1,294,829	426,442	1,293,978	426,030
Total Sales & Transportation	7,713,898	$31,179,682	7,713,898	$36,066,523	7,813,942	$36,623,616

1/ Gas rates effective with service rendered on and after January 1, 1995, PGA effective with bills rendered on and after December 1, 2002, exclusive of surcharge.

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Montana-Dakota Utilities Co.
Gas Utility - South Dakota
Summary of Revenues
Twelve Months Ended June 30, 2002
Projected 2003

Rate Reporting Class	Projected 2002 1/ Dk	Projected 2002 1/ Revenue	Projected 2003 1/ Dk	Projected 2003 1/ Revenue
Sales				
Residential				
Residential	3,119,384	$20,324,132	3,151,151	$20,560,052
Total Residential	3,119,384	20,324,132	3,151,151	20,560,052
Air Force				
Interruptible	569,719	1,753,026	569,719	1,753,026
Total Air Force	569,719	1,753,026	569,719	1,753,026
Firm General				
Firm General	2,755,702	13,942,837	2,776,777	14,062,198
Total Firm General	2,755,702	13,942,837	2,776,777	14,062,198
Interruptible				
Small Interruptible	38,760	188,950	38,760	188,950
Large Interruptible	83,120	269,779	83,120	269,779
Total Interruptible	121,880	458,729	121,880	458,729
Total Sales	6,566,685	36,478,724	6,619,527	36,834,005
Transportation				
Small Interruptible	370,750	208,592	364,450	205,543
Large Interruptible	694,670	152,356	664,670	147,046
Total Transportation	1,065,420	360,948	1,029,120	352,589
Total Sales & Transportation	7,632,105	$36,839,672	7,648,647	$37,186,594

1/ Gas rates effective with service rendered on and after January 1, 1995, PGA effective with bills rendered on and after December 1, 2002, exclusive of surcharge.

MONTANA-DAKOTA UTILITIES CO.
PER BOOKS REVENUE BY CUSTOMER CLASS
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002

	Jul 01	Aug 01	Sept 01	Oct 01	Nov 01	Dec 01	Jan 02	Feb 02	Mar 02	Apr 02	May 02	Jun 02	Total
ales													
Residential	$622,740	$542,403	$587,044	$938,172	$1,186,136	$2,037,839	$2,445,455	$2,213,671	$2,261,111	$1,850,208	$1,509,357	$792,500	$16,986,636
Firm General	562,089	503,096	495,805	660,669	814,902	1,304,387	1,622,725	1,498,723	1,522,754	1,329,709	1,069,492	615,857	12,000,208
Air Force	31,309	16,335	16,916	22,818	57,870	152,930	215,019	218,279	153,486	213,712	162,214	85,582	1,346,470
Small Interruptible	11,884	8,538	7,402	8,365	10,022	14,993	21,050	20,669	22,178	13,645	19,934	11,527	170,207
Large Interruptible	13,426	10,473	10,645	16,140	22,729	20,734	22,821	21,913	19,040	18,941	25,095	13,455	215,412
Total Sales	1,241,448	1,080,845	1,117,812	1,646,164	2,091,659	3,530,883	4,327,070	3,973,255	3,978,569	3,426,215	2,786,092	1,518,921	30,718,933
ransportation													
Small Interruptible	13,709	16,173	15,960	16,367	22,680	23,488	27,077	27,966	23,961	28,985	21,248	18,149	255,763
Large Interruptible	17,473	19,492	19,823	18,807	18,994	16,707	17,277	18,130	13,832	15,419	15,656	13,376	204,986
Total Transportation	31,182	35,665	35,783	35,174	41,674	40,195	44,354	46,096	37,793	44,404	36,904	31,525	460,749
otal South Dakota	$1,272,630	$1,116,510	$1,153,595	$1,681,338	$2,133,333	$3,571,078	$4,371,424	$4,019,351	$4,016,362	$3,470,619	$2,822,996	$1,550,446	$31,179,682

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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 DEPRECATION EXPENSE AND AMORTIZATION
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

	6/30/02	Projected 1/	
	Per Books	2002	2003
Distribution	$1,336,678	$1,379,366	$1,443,840
General	112,476	138,748	199,034
General - Intangible	1,119	1,058	1,040
Common	54,003	55,936	62,638
Common - Intangible	103,344	110,478	131,022
Total	$1,607,620	$1,685,586	$1,837,574

1/ See Rule 20:10:13:64, Statement E, pages 2 and 3 for the calculation of depreciation expense.

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION RATES
GAS UTILITY - SOUTH DAKOTA

Acct. No.	Account	Depreciation Rate
	Distribution Plant	
374.2	Rights of Way	2.58%
375	Structures & Improvements	2.40%
376	Mains	4.18%
378	Meas. & Reg. Equip.-General	2.30%
379	Meas. & Reg. Equip.-City Gate	2.74%
380	Services	8.22%
381	Positive Meters	2.58%
383	Service Regulators	2.37%
385	Ind. Meas. & Reg. Station Eqpt.	1.91%
386.2	Other Property on Cust. Premise	9.35%
387.1	Cathodic Protection Equip.	5.21%
387.2	Other Distribution Equip.	5.21%
	Total Distribution Plant	
	General Plant	
390	Structures and Improvements	2.34%
391.1	Furniture and Fixtures	4.05%
391.3	Computer Equip. - PC	12.50%
393	Stores Equipment	0.90%
394.1	Tools,Shop&Gar. Eq.-Non-Un.	3.57%
394.3	Vehicle Maintenance Equip.	4.21%
394.4	Vehicle Refueling Equip.	9.35%
395	Laboratory Equipment	2.32%
397.1	Radio Comm. Equip.-Fixed	3.67%
397.2	Radio Comm. Equip.-Mobile	3.67%
397.3	General Tele. Comm. Equip.	6.56%
397.5	Supervisory & Tele. Equip.	6.67%
397.6	Scada System	15.07%
398	Miscellaneous Equipment	0.59%
	Common Plant	
390	Structures and Improvements	3.76%
391.1	Furniture and Fixtures	1.48%
391.2	Computer Equip.- Bull/AS400	14.17%
391.3	Computer Equip. - PC	12.50%
391.5	Computer Equip. - Other	26.51%
393	Stores Equipment	3.36%
394.1	Tools, Shop & Gar. Equip.	3.44%
394.3	Vehicle Maint. Equip.	4.46%
394.4	Vehicle Refueling Equip.	8.42%
397.1	Radio Comm. Equip.-Fixed	4.33%
397.2	Radio Comm. Equip.-Mobile	6.68%
397.3	General Tele. Comm. Equip.	10.62%
397.5	Supervisory & Tele. Equip.	0.59%
397.8	Network Equipment	12.50%
398	Miscellaneous Equipment	2.51%

MONTANA-DAKOTA UTILITIES CO.
RECONCILIATION OF DEPRECIABLE GAS PLANT
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

	Balance @ 6/30/01	Balance @ 6/30/02	Average Balance
Depreciable Plant			
Distribution	$28,958,999	$30,054,146	$29,506,573
General	2,101,859	5,506,845	3,804,352
General - Amortized	139,667	135,079	137,373
	$31,200,525	$35,696,070	$33,448,298
Depreciable Plant Charged to a Clearing Account			
Transportation Equipment	$1,491,320	$1,632,976	$1,562,148
Tools, Shop & Garage Equipment - Unitized	73,712	57,875	65,793
Power Operated Equipment	82,045	85,741	83,893
Work Equipment	1,147,411	1,132,033	1,139,722
	$2,794,488	$2,908,625	$2,851,556
Non-Depreciable Plant			
Distribution	$29,992	$30,306	$30,149
General	105,845	582,076	343,960
	$135,837	$612,382	$374,109
Common Plant in Service - Gas			
Depreciable	$1,189,475	$996,085	$1,092,780
Charged to Clearing Account	117,319	135,710	126,515
Depreciable - Amortized	947,362	1,059,787	1,003,575
Non-Depreciable	39,663	31,426	35,544
	$2,293,819	$2,223,008	$2,258,414
Total Gas Plant in Service	$36,424,669	$41,440,085	$38,932,377

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.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

	Utility				Total
	Gas	Electric	Total	Non-Utility	Company
Operating Revenue	$156,524,998	$164,209,713	$320,734,711		$320,734,711
Non-Utility Income (before income taxes)					
Total Revenue	$156,524,998	$164,209,713	$320,734,711		$320,734,711
Operating Expense:					
O&M Expense	137,381,415	101,824,331	239,205,746		239,205,746
Depreciation Expense	8,162,516	19,484,871	27,647,387		27,647,387
Taxes Other than Income	4,618,758	7,637,428	12,256,186		12,256,186
Total Operating Expense	150,162,689	128,946,630	279,109,319		279,109,319
Operating Income	6,362,309	35,263,083	41,625,392		41,625,392
Interest Expense	3,447,436	7,823,359	11,270,795		11,270,795
Book Taxable Income before Adjustments	2,914,873	27,439,724	30,354,597		30,354,597
Deductions and Adjustments to Book Income:					
Tax Deductions	(6,516,013)	(7,853,450)	(14,369,463)	(855,421)	(15,224,884)
Preferred Dividend Paid Deduction	41,490	132,606	174,096		174,096
Total Deductions and Adjustments	(6,474,523)	(7,720,844)	(14,195,367)	(855,421)	(15,050,788)
Taxable Income - Before State Income Tax	9,389,396	35,160,568	44,549,964	855,421	45,405,385
Less: Deductible State Income Taxes	780,125	1,876,571	2,656,696		2,656,696
Federal Taxable Income	8,609,271	33,283,997	41,893,268	855,421	42,748,689
Federal Income Taxes @ 35%	3,013,245	11,649,399	14,662,644	299,397	14,962,041
Credits and Adjustments	(303,914)	(518,584)	(822,498)		(822,498)
State Income Taxes	780,125	1,876,571	2,656,696		2,656,696
Federal and State Income Taxes	3,489,456	13,007,386	16,496,842	299,397	16,796,239
Rounding and Prior Year's Adjustment	(51,776)	(87,254)	(139,030)		(139,030)
Total Federal and State Income Taxes	$3,437,680	$12,920,132	$16,357,812	$299,397	$16,657,209

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
TAX DEDUCTIONS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

	Utility				Total
1900 Account M-1's	Gas	Electric	Total	Non-Utility	Company
Management Incentive Compensation	($166,547)	($273,451)	($439,998)	($7,560)	($447,558)
Pension Expense	1,739,258	1,637,401	3,376,659		3,376,659
Sundry Reserves	16,686	46,259	62,945		62,945
Reserve for Deferred Maintenance	15,732	28,798	44,530		44,530
Property Insurance Adjustment	(57,285)	(42,424)	(99,709)		(99,709)
Bad Debt Expense	219,878	(2,407)	217,471	(952)	216,519
Accrued Vacation	136,541	144,858	281,399		281,399
Capitalized Overheads	(925,251)		(925,251)		(925,251)
Customer Advances	42,191	(394,485)	(352,294)		(352,294)
Restricted Stock Bonus Plan	138,597	183,271	321,868		321,868
Supplemental Income Security Plan				(1,729,355)	(1,729,355)
FAS 106 - OPRB	81,602	102,829	184,431	22,052	206,483
Deferred Compensation	(42,491)	(77,780)	(120,271)		(120,271)
BOD Retirement	(657,291)	(1,201,279)	(1,858,570)		(1,858,570)
Demand Charges	79,982		79,982		79,982
PCB related income	(19,586)		(19,586)		(19,586)
Contingency Reserve				860,394	860,394
2820 Account M-1's					
Liberalized Depreciation and Other Property Timing Differences	(1,337,470)	(6,136,493)	(7,473,963)		(7,473,963)
Contributions in Aid of Construction	(46,714)	(21,717)	(68,431)		(68,431)
2830 Account M-1's					
Unrecovered Purchased Gas Cost	(5,103,058)		(5,103,058)		(5,103,058)
Amortization of Loss on Bond Retirements	(345,849)	(827,864)	(1,173,713)		(1,173,713)
Defered Gain on Sale of Building		(884,358)	(884,358)		(884,358)
FAS 106 - Deferred Expense	(110,861)		(110,861)		(110,861)
Gas IRP	(88,708)		(88,708)		(88,708)
Permanent M-1's					
Meals & Entertainment	(71,967)	(129,759)	(201,726)		(201,726)
Federal Nonhwy Use Tax Credit	(13,402)	(4,849)	(18,251)		(18,251)
Total M-1 Deductions	($6,516,013)	($7,853,450)	($14,369,463)	($855,421)	($15,224,884)

MONTANA DAKOTA UTILITIES, CO.
COMPUTATION OF INCOME TAX LIABILITY AND TAX SAVINGS
BASED ON MDU RESOURCES GROUP, INC. 2001
CONSOLIDATED FEDERAL INCOME TAX RETURN

	Montana-Dakota Utilities Co.	MDU Resources Group. Inc. (1)
Net Taxable Income (Loss)	$48,062,511	$176,829,728
Federal Income Tax:		
Statutory Taxes @ 35%	$16,821,880	$61,890,405
Less Credits:		
Nonconventional Source Fuel Credit		542,299
Carryforward of General Business Credit		10,510
Credit for Prior Year Minimum Tax		9,908
Total Tax	$16,821,880	$61,327,688
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 JUNE 30, 2002

	Per Books
Operating Revenue	$31,494,705
Operating Expense:	
O&M Expense	27,614,688
Depreciation Expense	1,607,620
Taxes Other than Income	719,996
Total Operating Expense	29,942,304
Operating Income	1,552,401
Interest Expense	690,972
Book Taxable Income before Adjustments	861,429
Deductions and Adjustments to Book Income:	
Tax Deductions 1/	(1,307,395)
Preferred Dividend Paid Deduction	8,064
Total Deductions and Adjustments	(1,299,331)
Federal Taxable Income	2,160,760
Federal Income Taxes @ 35%	756,266
Credits and Adjustments	(210,207)
Total Federal and State Income Taxes	$546,059

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MONTANA-DAKOTA UTILITIES CO.
INCOME TAX DEDUCTIONS
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	6/30/2002	2002	2003
1900 Account M-1's			
Management Incentive Compensation	($32,446)		
Pension Expense	341,523	242,447	103,900
Sundry Reserves	3,171		
Reserve for Deferred Maintenance	3,062		
Property Insurance Adjustment	(11,149)		
Bad Debt Expense	50,467		
Accrued Vacation	26,600		
Capitalized Overheads	(180,254)		
Customer Advances	957		
Restricted Stock Bonus Plan	27,001		
FAS 106 - OPRB	15,897	(82,890)	(82,890)
Deferred Compensation	(8,278)		
BOD Retirement	(128,072)		
Demand Charges	12,771		
PCB Related Income	(9,863)		
Plant Reclassification	17,187		
2820 Account M-1's			
Liberalized Depreciation and Other Property Timing Differences	(499,963)	(619,743)	(720,225)
Contributions in Aid of Construction	(705)		
2830 Account M-1's			
Purchased Gas Cost Adjustment	(836,712)	3,784,518	2,349,393
Amortization of Loss on Bond Retirements	(65,811)	(74,774)	(82,574)
FAS 106 Deferred Expense	(15,863)	(15,864)	(15,864)
Permanent M-1's			
Meals & Entertainment	(14,214)	(20,773)	(20,773)
Federal Nonhwy Use Tax Credit	(2,701)		
Total M-1 Deductions	($1,307,395)	$3,212,921	$1,530,967

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
INTEREST EXPENSE ANNUALIZATION
PROJECTED 2002-2003

	Projected	
	2002	2003
Rate Base	$14,921,823	$17,793,768
Long Term Debt Ratio	43.708%	44.674%
Long Term Debt Cost	9.241%	9.027%
Weighted Cost of Debt	4.039%	4.033%
Interest Expense	$602,692	$717,623

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
CALCULATION OF CURRENT INCOME TAXES
PROJECTED 2002-2003

	Projected	
	2002	2003
Operating Revenues		
Sales Revenues	$36,478,724	$36,834,005
Transportation Revenues	360,948	352,589
Other Revenues	147,425	147,425
Total Operating Revenues	36,987,097	37,334,019
Operating Expenses		
Operation and Maintenance		
Cost of Gas	26,720,886	26,946,077
Other O&M	6,672,199	7,292,809
Total O&M	33,393,085	34,238,886
Depreciation Expense	1,685,586	1,837,574
Taxes other Than Income	720,517	775,067
Total Operating Expenses	35,799,188	36,851,527
Operating Income before Income Taxes	1,187,909	482,492
Deductions and Adjustments to Book Income:		
Interest Expense	602,692	717,623
Preferred Dividend Paid	8,064	8,064
Other Tax Deductions 1/	3,212,921	1,530,967
Total Adjustments to Taxable Income	3,823,677	2,256,654
Taxable Income	(2,635,768)	(1,774,162)
Federal & State Income Taxes @ 35%	($922,519)	($620,957)

1/ Statement K, page 5

MONTANA DAKOTA UTILITIES, CO.
ACCUMULATED DEFERRED INCOME TAXES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

BALANCE AT:	Total Company	Electric	Gas	Other	Non-Utility
ACCOUNT 190:					
July 31, 2001	(19,021,572)	(744,285)	772,819	(11,953,002)	(7,097,104)
August 31, 2001	(17,921,770)	(687,896)	1,848,861	(11,931,705)	(7,151,030)
September 30, 2001	(17,023,732)	(631,507)	2,727,225	(11,914,494)	(7,204,956)
October 31, 2001	(16,731,098)	(575,118)	3,015,477	(11,912,575)	(7,258,882)
November 30, 2001	(17,477,639)	(407,936)	2,642,567	(11,708,283)	(8,003,987)
December 31, 2001	(19,215,849)	(1,057,909)	815,137	(11,481,213)	(7,491,864)
January 31, 2002	(20,697,507)	(1,006,195)	(628,765)	(11,527,775)	(7,534,772)
February 28, 2002	(21,531,075)	(946,165)	(1,447,632)	(11,559,598)	(7,577,680)
March 31, 2002	(22,084,076)	(887,143)	(1,990,641)	(11,585,704)	(7,620,588)
April 30, 2002	(21,850,214)	(827,269)	(1,763,442)	(11,593,474)	(7,666,029)
May 31, 2002	(21,073,699)	(767,392)	(1,009,435)	(11,587,675)	(7,709,197)
June 30, 2002	(21,046,248)	(707,510)	56,822	(12,642,058)	(7,753,502)
ACCOUNT 282: (Other Property)					
July 31, 2001	70,962,168	56,214,082	15,501,233	(790,436)	37,289
August 31, 2001	70,755,032	56,020,050	15,472,501	(774,808)	37,289
September 30, 2001	70,451,337	55,826,018	15,353,656	(765,626)	37,289
October 31, 2001	70,203,623	55,631,986	15,314,912	(780,564)	37,289
November 30, 2001	69,978,459	55,742,278	15,339,815	(1,153,829)	50,195
December 31, 2001	69,868,767	55,516,685	15,266,513	(959,589)	45,158
January 31, 2002	69,544,769	55,314,638	15,224,195	(1,039,222)	45,158
February 28, 2002	69,244,018	55,112,591	15,181,877	(1,095,608)	45,158
March 31, 2002	68,952,284	54,910,544	15,139,559	(1,142,977)	45,158
April 30, 2002	68,689,473	54,708,497	15,097,241	(1,161,423)	45,158
May 31, 2002	68,448,065	54,506,450	15,054,923	(1,158,466)	45,158
June 30, 2002	68,219,870	54,304,403	15,012,605	(1,142,296)	45,158
ACCOUNT 283: (Other)					
July 31, 2001	(1,065,542)	372,637	(4,036,649)	2,007,990	590,480
August 31, 2001	(1,306,659)	372,637	(4,236,008)	1,966,232	590,480
September 30, 2001	(4,102,664)	372,637	(6,990,255)	1,924,474	590,480
October 31, 2001	(4,781,755)	372,637	(7,627,588)	1,882,716	590,480
November 30, 2001	(3,081,495)	445,237	(5,918,985)	1,840,961	551,292
December 31, 2001	(5,874,353)	445,237	(8,219,922)	1,692,171	208,161
January 31, 2002	(4,502,998)	445,237	(6,809,798)	1,653,402	208,161
February 28, 2002	(3,651,276)	445,237	(5,919,307)	1,614,633	208,161
March 31, 2002	(2,951,344)	445,237	(5,180,606)	1,575,864	208,161
April 30, 2002	(2,190,950)	445,237	(4,381,443)	1,537,095	208,161
May 31, 2002	(2,324,670)	445,237	(4,476,394)	1,498,326	208,161
June 30, 2002	(2,505,883)	445,237	(4,618,838)	1,459,557	208,161
TOTAL COMPANY					
July 31, 2001	50,875,054	55,842,434	12,237,403	(10,735,448)	(6,469,335)
August 31, 2001	51,526,603	55,704,791	13,085,354	(10,740,281)	(6,523,261)
September 30, 2001	49,324,941	55,567,148	11,090,626	(10,755,646)	(6,577,187)
October 31, 2001	48,690,770	55,429,505	10,702,801	(10,810,423)	(6,631,113)
November 30, 2001	49,419,325	55,779,579	12,063,397	(11,021,151)	(7,402,500)
December 31, 2001	44,778,565	54,904,013	7,861,728	(10,748,631)	(7,238,545)
January 31, 2002	44,344,264	54,753,680	7,785,632	(10,913,595)	(7,281,453)
February 28, 2002	44,061,667	54,611,663	7,814,938	(11,040,573)	(7,324,361)
March 31, 2002	43,916,864	54,468,638	7,968,312	(11,152,817)	(7,367,269)
April 30, 2002	44,648,309	54,326,465	8,952,356	(11,217,802)	(7,412,710)
May 31, 2002	45,049,696	54,184,295	9,569,094	(11,247,815)	(7,455,878)
June 30, 2002	44,667,739	54,042,130	10,450,589	(12,324,797)	(7,500,183)

MONTANA-DAKOTA UTILITIES CO.
DEFERRED INCOME TAXES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	6/30/02	2002	2003
Gas Utility - Rate Base Deductions:			
Depreciation, Retirements and Other Timing Differences Required to be Normalized	($38,416)	($123,083)	($115,371)
Contributions In Aid of Construction	(425)		
Customer Advances	335		
Total Rate Base Deductions	(38,506)	(123,083)	(115,371)
Gas Utility - Current Timing Differences:			
Management Incentive Compensation	(11,356)		
Pension Expense	119,533	24,122	(27,100)
Sundry Reserves	1,110		
Reserve for Deferred Maintenance	1,036		
Property Insurance Adjustment	(3,902)		
Bad Debt Expense	17,663		
Accrued Vacation	9,310		
Capitalized Overheads	(63,089)		
Restricted Stock Bonus Plan	9,450		
FAS 106	5,564		
Deferred Compensation	(2,897)		
BOD Retirement	(44,825)		
Demand Charges	4,470		
PCB Related Income	(1,295)		
Unrecovered Purchased Gas Cost	(292,849)	1,324,581	822,288
Amort of Loss on Bond Retirements	(23,034)		
FAS 106 Deferred Expense	(5,552)		
Closing/Filing Adj.	211,943		
Total Current Timing Differences	(68,720)	1,348,703	795,188
Total	($107,226)	$1,225,620	$679,817

MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF ACCUMULATED DEFERRED INCOME TAXES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

	Total Company		South Dakota		
	Balance 06/30/01	Balance 06/30/02	Balance 06/30/01	Balance 06/30/02	Average Balance
Gas Utility - Rate Base Deductions:					
Depreciation, Retirements and Other Timing Differences Required to be Normalized	$10,421,527	$10,285,543	$1,948,966	$1,913,425	$1,931,196
Contributions In Aid of Construction	(143,527)	(175,753)	(63,504)	(63,929)	($63,716)
North Dakota Full Normalization	607,509	548,596			
Customer Advances for Construction	(222,618)	(207,018)	(25,041)	(28,146)	(26,594)
Montana Rate Case Adjustments	222,821	268,604			
Total	$10,885,712	$10,719,972	$1,860,421	$1,821,350	$1,840,886
Gas Utility - Current Timing Differences:					
Management Incentive Compensation	($84,084)	($74,073)			
Pension Expense	390,808	1,046,431			
Uncollectable Accounts	(119,113)	(35,561)			
Unbilled Revenues	172,888	172,888			
Workers Comp	(20,018)	(20,018)			
Capitalized Overheads	(408,850)	(922,359)			
Restricted Stock Bonus Plan	(174,498)	(121,581)			
Contingency Reserve	(3,940)	(3,940)			
Delivered But Unbilled	623,187	623,187			
FAS 109 Adjustment	(8,089,844)	(8,521,610)			
BOD Retirement		(250,958)			
Rate 71 Refund	14,738	14,738			
FAS 106	343,010	386,110			
Demand Charges	268,673	299,421			
PCB Related Income	(136,394)	61,720			
Rate Case Expense	(7,856)	(7,856)			
Unrecovered Purchased Gas Cost	(3,783,825)	(5,733,543)			
Environmental Tax	4,386	4,386			
Gas IRP	133,588	98,526			
Total Gas Utility	($10,877,144)	($12,984,092)			

MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF UNAMORTIZED INVESTMENT TAX CREDITS
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

	Total Company	South Dakota
Balance @		
June 30, 2001	$628,846	$46,069
June 30, 2002	$557,716	$33,248
Average Balance	$593,281	$39,659

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED DEFERRED INCOME TAXES
ACCUMULATED INVESTMENT TAX CREDITS
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2002-2003

	2001	Balance @ 6/30/02	Projected 2002			Projected 2003		
			Changes 1/	Balance	Average	Changes	Balance	Average
Accumulated Deferred Income Taxes								
Liberalized Depreciation	$1,939,905	$1,913,425						
Contribution in Aid of Construction	(63,929)	(63,929)						
Customer Advances	(28,146)	(28,146)						
Balance	$1,847,830	$1,821,350	($123,083)	$1,724,747	$1,786,289	($115,371)	$1,609,376	$1,667,062
Accumulated Investment Tax Credits								
Balance	$40,710	$33,248	($7,462)	$25,786	$33,248	($14,924)	$10,862	$18,324

1/ Changes in deferred taxes are for calendar year 2002 and adjust 2001 balances.
Changes in ITCs are for six months of 2002 and adjust June 30, 2002 balances.

MDU RESOURCES GROUP, INC.
RECONCILIATION OF NET INCOME PER BOOKS WITH TAXABLE INCOME PER FEDERAL INCOME TAX RETURN
FOR TAX YEARS 1998-2001

M-1 Line No.		2001	2000	1999	1998
1	**Net Income per Books**	$155,848,506	$111,028,299	$84,079,784	$34,106,960
2	**Federal Income Tax**	10,359,280	11,415,372	8,602,112	8,425,172
3	**Excess of Capital Losses Over Capital Gains**	0	0	0	0
4	**Income Subject to Tax not Recorded on Books This Year:**				
	Other				
	Dividends Received from Subsidiary Companies	39,709,000	34,649,500	28,591,800	26,063,100
	Jt Venture & Partnership Ordinary Income	99,639	100,999	71,696	(2,027)
	Contributions in Aid of Construction	268,101	287,951	(78,979)	360,640
	Customer Advances	330,767	(31,713)	230,817	28,917
	Federal Non-highway Use Tax Credit	18,761	19,658	17,723	18,828
	Gain on Retirement of Assets - Tax	887,626	(371,684)	(185,636)	(181,538)
	Total	41,313,894	34,654,711	28,647,421	26,287,920
5	**Expenses Recorded on Books This Year not Deducted on This Return:**				
	Depreciation	26,361,318	25,400,418	24,324,027	23,922,051
	Meals & Entertainment	226,971	210,693	167,207	174,109
	Other				
	Increase in Capitalized Overheads	805,471	34,186	124,248	17,853
	Increase in Capitalized Overheads - Stores	64,697	65,030	58,298	51,745
	Rate Case Expense				66,368
	Demand Charges	8,194	251,462	109,107	
	Unrecovered Purchased Gas Costs	21,010,649	4,116,950	2,304,705	
	Bad Debt Expense per Books	1,593,836	1,081,029	734,276	580,938
	Increase in Capitalized Overheads - Non-operating	62,678	52,469	28,968	30,667
	Supplemental Income Security Plan	83,247	1,542,306	2,444,095	1,286,888
	Capitalized Property Taxes	70,406	117,138	111,560	74,908
	State Income Tax Accrual per Books	1,217,822	2,177,260	1,520,817	2,021,388
	Accrued Coal Costs				338,906
	Post Retirement Benefits Accrued	1,923,299		429,419	784,392
	Increase in Sundry Reserves		54,439		
	Capitalized Interest Expense	337,186	169,399	231,213	154,594
	Amortizaiton per Books	2,473,984	2,121,959	1,408,993	1,359,076
	Accrued Vacation Pay		381,575	525,397	
	Amortization of Loss on Bond Retirements	1,295,507	1,388,692	1,481,731	470,675
	Book Depreciation Charged to Expense	1,082,985	1,008,364	952,351	957,221
	Capitalized Tax Depreciation	623,116	571,179	514,448	508,610
	Lobbying Expense	114,117	72,226	97,881	75,741
	Deferred Compensation for Directors	125,828	200,915	26,701	122,250
	Deferred Compensation - Net Deferral	463,790			48,468
	Penalties	6,086	120	465	575
	Property Insurance Adjustment	107,240	271,011	267,652	
	Reusable Property to Expense	2,584	2,586	694	5,464
	Integrated Resource Plan	88,708	88,708	100,961	144,390
	Workers Compensation			6,880	
	Restricted Stock Bonus Plan	827,981	502,014	408,146	86,797
	Total Other	34,389,411	16,271,017	13,889,006	9,187,914
6	**Total of Lines 1 Through 5**	$268,499,380	$198,980,510	$159,709,557	$102,104,126
7	**Income Recorded on Books This Year not Included on This Return:**				

MDU RESOURCES GROUP, INC.
RECONCILIATION OF NET INCOME PER BOOKS WITH TAXABLE INCOME PER FEDERAL INCOME TAX RETURN
FOR TAX YEARS 1998-2001

M-1 Line No.		2001	2000	1999	1998
	Other				
	Book Gain on Disposition of Property	2,311	2,164	(9,795)	(13,072)
	G/L on Interco. Trans. under reg sec 1.1502-13	884,358			
	Joint venture & partnership operating income	20,000			
	Equity in Earnings of Subsidiary Companies	135,692,353	87,788,729	64,143,724	15,920,717
	Allowance for Funds Used During Construction	185,066	157,410	419,934	46,892
		136,784,088	87,948,303	64,553,863	15,954,537
8	**Deductions on This Return not Charged Against Book Income This Year:**				
	Depreciation	22,657,193	23,839,600	22,863,065	23,218,116
	Contributions Carryover	4,537,084	6,639,606		
	Other				
	Pension Expense per Return	3,965,568	3,849,479	1,755,783	347,565
	Demand Charges				287,928
	Post Retirement Benefits	1,894,963	510,702		
	Bad Debt Expense per Return	1,814,870	764,866	687,463	593,641
	Decrease in Sundry Reserves	67,119		2,911	28,435
	Property Insurance Adjustment				268,726
	CNG Refueling Facilities Deduction				4,022
	Deferred Compensation		246,937	599,782	
	Unrecovered Purchased Gas Cost				166,448
	Environmental Costs	19,586	569,234	190,153	207,357
	KESOP Incentive Compensation	4,379,752	1,439,653	266,178	3,303,387
	State Income Tax Accrual per Return	3,062,638	1,729,801	2,198,158	1,395,594
	Reserve for deferred maintenance	46,599			70,801
	Vacation accrual	324,210			442,705
	Workers compensation	181,167			
	1991 Interest Expense		10,124		
	R & D - Software Development Costs				1,096,693
	Expenses for the Retirement of Assets	344,330	355,479	386,135	449,836
	Restricted Stock Bonus Plan - Dividends	468,699	134,133	145,244	4,732
		16,569,501	9,610,408	6,231,807	8,667,870
9	**Add Lines 7 and 8**	180,547,866	128,037,917	93,648,735	47,840,523
10	**Income (Form 1120, Page 1, Line 28) - Line 6 less Line 9**	87,951,514	70,942,593	66,060,822	54,263,603
	Less: Special Deductions	39,889,003	35,027,503	29,167,803	26,815,103
	Taxable Income (Form 1120, Page 1, Line 30)	$48,062,511	$35,915,090	$36,893,019	$27,448,500

MONTANA DAKOTA UTILITIES, CO.
Difference in Book and Tax Depreciation - Gas Utility
FOR THE TWELVE MONTHS ENDED JUNE 30, 2002

Tax Depreciation

CIAC's - MACRS	($80,413)
Depreciation	7,285,124
Capitalized Interest Expense	(100,981)
Capitalized Tax Depreciation	(178,867)
Capitalized Inventory on Stores Inventory	(11,699)
Capitalized Property Taxes	(28,165)
Expenses for the Retirement of Assets	69,919
Retirement of Assets	(61,714)
Total Gas	$6,893,204

Book Depreciation

Depreciation Expense	8,199,473
Amortization Expense	524,657
Allowance for Funds used during Construction	(56,681)
Total Book Depreciation	$8,667,449
Book over Tax Depreciation	$1,774,245

MONTANA - DAKOTA UTILITIES CO.
NET TAXABLE INCOME (LOSS) FOR EACH COMPANY INCLUDED IN MDU RESOURCES GROUP, INC.'S 2001 CONSOLIDATED FEDERAL INCOME TAX RETURN

COMPANY	TAXABLE INCOME (LOSS)	EXCESS TAX DEPRECIATION	TAXABLE INCOME (LOSS) AFTER ELIMINATION	SYSTEM TAX LIABILITY
Montana - Dakota Utilities Co.	$ 48,062,511	$ (7,884,210)	$ 40,178,301	$ 16,821,880
Centennial Energy Holdings, Inc.	0	0	0	0
Centennial Holdings Capital Corp.	(894,130)	0	(894,130)	(312,946)
Centenntial Power Inc.	(532,774)	0	(532,774)	(186,471)
RMP Montana Acquisition, Inc.	0	0	0	0
Futuresource Capital Corp.	(23,657)	459,923	436,266	(8,280)
Intersource Insurance Company	0	0	0	0
MDU Resources International, Inc.	(1,025,515)	0	(1,025,515)	(358,930)
Utility Services, Inc.	(122)	0	(122)	(43)
International Line Builders, Inc.	1,591,950	(163,834)	1,428,116	557,183
ILB Hawaii, Inc.	10,672	0	10,672	3,735
Loy Clark Pipeline Co.	(4,237,385)	179,353	(4,058,032)	(1,483,085)
Loy Clark Pipeline of Washington, Inc.	0	0	0	0
High Line Equipment, Inc.	1,555,208	34,046	1,589,254	544,323
Rocky Mountain Contractors, Inc.	6,233,121	(121,673)	6,111,448	2,181,592
Williams Construction Company, Inc.	1,074,861	202,620	1,277,481	376,201
Hamlin Electric Company	1,402,326	510,780	1,913,106	490,814
Harp Engineering, Inc	(301,323)	15,394	(285,929)	(105,463)
Pouk & Steinle, Inc.	814,024	33,208	847,232	284,908
The Wagner-Smith Company	2,709,709	114,339	2,824,048	948,398
Wagner-Smith Equipment Co.	2,616,368	1,476,696	4,093,064	915,729
Wagner-Smith Pumps & Systems, Inc.	(10,633)	39,370	28,737	(3,722)
Frebco, Inc.	832,996	30,255	863,251	291,549
Newco, Inc.	158,412	7,679	166,091	55,444
Bell Communications, Inc.	44,919	2,374	47,293	15,722
Bell Electric Contractors, Inc.	(237,841)	21,999	(215,842)	(83,244)
Capital Electric Construction Company	2,209,818	227,023	2,436,841	773,436
Capital Electric Line Builders	2,032,657	411,737	2,444,394	711,430
Oregon Electric Construction, Inc.	241,284	44,890	286,174	84,449
WBI Holdings, Inc.	0	0	0	0
Fidelity E & P Company	6,651,229	7,025,085	13,676,314	2,051,249
Fidelity Oil Company	17,708,485	(3,269,885)	14,438,600	5,919,920
Fidelity Oil Holdings, Inc.	13,125,398	(44,713)	13,080,685	4,585,964
WBI Production, Inc.	7,605,230	1,559,711	9,164,941	2,661,831
WBI Pipeline & Storage Group, Inc.	0	0	0	0
Williston Basin Interstate Pipeline Co.	29,137,835	14,227	29,152,062	10,198,242
WBI Southern, Inc.	(685,311)	(99,221)	(784,532)	(239,859)
WBI Offshore Pipeline, Inc.	566,568	(7,415)	559,153	198,299
Kentucky Pipeline & Storage Company, Inc.	6,712,296	53,030	6,765,326	2,349,304
Bitter Creek Pipeline, LLC	(14,783,366)	15,015,268	231,902	(5,174,178)
WBI Energy Services, Inc.	0	0	0	0
Prairielands Energy Marketing, Inc.	1,531,934	(261,521)	1,270,413	536,177

MONTANA - DAKOTA UTILITIES CO.
NET TAXABLE INCOME (LOSS) FOR EACH COMPANY INCLUDED IN MDU RESOURCES GROUP, INC.'S 2001 CONSOLIDATED FEDERAL INCOME TAX RETURN

COMPANY	TAXABLE INCOME (LOSS)	EXCESS TAX DEPRECIATION	TAXABLE INCOME (LOSS) AFTER ELIMINATION	SYSTEM TAX LIABILITY
SAGE Gas Alliance, LLC	(12,147)	0	(12,147)	(4,251)
Innovatum, Inc.	(229,985)	262,806	32,821	(80,556)
Innovative Gas Services Inc.	876,752	(2,322)	874,430	306,863
Marcon Energy Corp.	21,276	0	21,276	7,447
Knife River Corporation	15,156,885	469,002	15,625,887	5,304,910
KRC Holdings, Inc.	(30,806,441)	3,985	(30,802,456)	(10,782,254)
KRC Aggregates, Inc.	829,778	11,113	840,891	290,422
Concrete, Inc.	2,664,387	415,425	3,079,812	932,535
DSS Company	7,034,784	334,277	7,369,061	2,462,174
LTM, Incorporated	(1,384,506)	2,963,733	1,579,227	(484,577)
Rogue Aggregates, Inc.	1,084,450	527,667	1,612,117	379,558
Medford Ready Mix, Inc.	455,488	49,451	504,939	159,421
Southern Oregon Underground, Inc.	(480,259)	145,971	(334,288)	(168,091)
Alaska Basic Industries, Inc.	0	0	0	0
Anchorage Sand & Gravel Company, Inc.	6,879,124	(100,508)	6,778,616	2,407,693
Baldwin Contracting Company, Inc.	4,537,577	123,325	4,660,902	1,588,152
Knife River Dakota, Inc.	5,693,446	0	5,693,446	1,992,706
Knife River Hawaii, Inc.	5,677,732	0	5,677,732	1,987,206
Knife River Marine, Inc.	165,908	35,774	201,682	58,068
Morse Brothers, Inc.	3,656,835	3,834,772	7,491,607	1,279,892
Hap Taylor & Sons, Inc.	2,410,593	1,060,068	3,470,661	843,708
JTL Group, Inc. - Montana	9,332,591	4,987,063	14,319,654	3,266,407
JTL Group, Inc. - Wyoming	1,813,326	(179,138)	1,634,188	634,664
Polson Ready Mix Concrete, Inc.	497,013	89,174	586,187	173,955
Connolly-Pacific Co.	(3,794,936)	1,017,305	(2,777,631)	(1,328,228)
Bauerly Brothers, Inc.	11,295,539	886,002	12,181,541	3,953,439
WHC, Ltd.	1,556,764	(61,208)	1,495,556	544,867
MDU RESOURCES GROUP INC. & INCLUDIBLE SUBISIDIARIES	$ 176,829,728	$ 32,500,272	$ 209,330,000	$ 61,327,688

MONTANA-DAKOTA UTILITIES CO.
ALLOWANCE FOR CURRENT TAX IN EXCESS OF TAX CALCULATED AT CONSOLIDATED TAX RATE FOR THE TWELVE MONTHS ENDING JUNE 30, 2002

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 STATE INCOME TAXES
CALCULATED AT CONSOLIDATED TAX RATE
FOR THE TWELVE MONTHS ENDING JUNE 30, 2002

This schedule is not applicable since Montana-Dakota Utilities Co. is not claiming an allowance for state income taxes in the cost of service.

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

Type of Tax	Total Company	South Dakota	Projected 2002	Projected 2003
Ad Valorem				
Distribution	$2,372,470	$323,536	$301,085	$315,159
General	185,717	40,639	53,190	68,126
Common	204,067	21,826	19,526	23,969
Intangible	4,130	1,046	1,195	1,390
Total Ad Valorem Taxes	2,766,384	387,047	$374,996	$408,644
O&M Related Taxes - Other				
FICA	1,313,290	250,469	272,868	293,770
Federal Unemployment	20,620	3,933		
State Unemployment	30,902	5,894		
Franchise	100,088	0		
Delaware Franchise	52,762	10,353	10,353	10,353
Total O&M Related Taxes	1,517,662	270,649	$283,221	$304,123
Other				
Gross Revenue Taxes	333,800	62,122	62,122	62,122
Highway Use Tax	370	72	72	72
Secretary of State	542	106	106	106
Total Other	334,712	62,300	62,300	62,300
Total Taxes Other Than Income	$4,618,758	$719,996	$720,517	$775,067

MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - SOUTH DAKOTA
PROJECTED 2002-2003

		Projected 2002		Projected 2003	
Function	Effective Tax Rate	Plant Balance	Ad Valorem Tax	Plant Balance	Ad Valorem Tax
Distribution	0.9888%	$30,449,566	$301,085	$31,872,837	$315,159
General	0.7521%	7,072,210	53,190	9,058,070	68,126
Common	1.7324%	1,127,114	19,526	1,383,548	23,969
Intangible	0.0980%	1,219,422	1,195	1,418,355	1,390
Total Ad Valorem Taxes		$39,868,312	$374,996	$43,732,810	$408,644

MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - SOUTH DAKOTA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

Function	Average Plant Balance @ 12/31/01	Ad Valorem Tax @ 12/31/01	Effective Tax Rate
Distribution	$29,090,118	$287,647	0.9888%
General	5,063,370	38,080	0.7521%
Common	1,139,124	19,734	1.7324%
Intangible 1/	1,067,113	1,046	0.0980%
Total	$36,359,725	$346,507	

1/ General and common intangible.

MONTANA-DAKOTA UTILITIES CO.
PAYROLL TAXES
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	6/30/02	2002 1/	2003 1/
FICA	$250,469		
Federal Unemployment	3,933		
State Unemployment	5,894		
Total	$260,296	$272,868	$293,770

1/ Caculated based on ratio of payroll taxes to labor for the twelve months ending June 30, 2002.

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002

	Total Company	South Dakota	Other	Reference
Operating Revenues				
Sales	$152,946,954	$30,893,615	$122,053,339	Statement I
Transportation	2,861,691	453,665	2,408,026	Statement I
Other	716,353	147,425	568,928	Statement I
Total Revenues	156,524,998	31,494,705	125,030,293	
Operating Expenses				
Operation and Maintenance				
Cost of Gas	106,488,405	21,351,949	85,136,456	Statement H
Other O&M	30,893,010	6,262,739	24,630,271	Statement H
Total O&M	137,381,415	27,614,688	109,766,727	
Depreciation	8,162,517	1,607,620	6,554,897	Statement J
Taxes Other Than Income	4,618,758	719,996	3,898,762	Statement L
Current Income Taxes	3,437,679	546,059	2,891,620	Statement K
Deferred Income Taxes	(1,757,478)	(107,226)	(1,650,252)	Statement K
Total Expenses	151,842,891	30,381,137	121,461,754	
Operating Income	$4,682,107	$1,113,568	$3,568,539	
Rate Base	$68,241,058	$14,829,782	$53,411,276	
Rate of Return	6.861%	7.509%	6.681%	

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002

	Total Company	South Dakota	Other	Reference
Gas Plant in Service	$191,084,175	$38,932,377	$152,151,798	Statement D
Accumulated Reserve for Depreciation	116,333,747	22,878,024	93,455,723	Statement E
Net Gas Plant in Service	74,750,428	16,054,353	58,696,075	
CWIP in Service Pending Reclassification	882,281	264,640	617,641	Statement D
Total Gas Plant in Service	75,632,709	16,318,993	59,313,716	
Additions				
Materials and Supplies	1,286,063	290,358	995,705	Statement F
Fuel Stocks	17,173	0	17,173	
Prepayments	197,969	50,818	147,151	Statement F
Gas in Underground Storage	2,901,924	0	2,901,924	
Other	423,894	174,494	249,400	Statement F
Total Additions	4,827,023	515,670	4,311,353	
Total Before Deductions	$80,459,732	$16,834,663	$63,625,069	
Deductions				
Accumulated Deferred Income Taxes	10,802,842	1,840,886	8,961,956	Statement K
Accumulated Investment Tax Credits	593,281	39,658	553,623	Statement K
Customer Advances	781,327	124,337	656,990	Statement F
Total Deductions	12,177,450	2,004,881	10,172,569	
Total Rate Base	$68,282,282	$14,829,782	$53,452,500	

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	Per Books	2002	2003
Operating Revenues			
Sales	$30,893,615	$36,478,724	$36,834,005
Transportation	453,665	360,948	352,589
Other	147,425	147,425	147,425
Total Revenues	31,494,705	36,987,097	37,334,019
Operating Expenses			
Operation and Maintenance			
Cost of Gas	21,351,949	26,720,886	26,946,077
Other O&M	6,262,739	6,672,199	7,292,809
Total O&M	27,614,688	33,393,085	34,238,886
Depreciation	1,607,620	1,685,586	1,837,574
Taxes Other Than Income	719,996	720,517	775,067
Current Income Taxes	546,059	(922,519)	(620,957)
Deferred Income Taxes	(107,226)	1,225,620	679,817
Total Expenses	30,381,137	36,102,289	36,910,387
Operating Income	$1,113,568	$884,808	$423,632
Rate Base	$14,829,782	$14,921,823	$17,793,768
Rate of Return	7.509%	5.930%	2.381%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - SOUTH DAKOTA
TWELVE MONTHS ENDED JUNE 30, 2002
PROJECTED 2002-2003

		Projected	
	6/30/02	2002	2003
Gas Plant in Service	$38,932,377	$39,868,312	$43,732,810
Accumulated Reserve for Depreciation	22,878,024	23,505,786	24,631,780
Net Gas Plant in Service	16,054,353	16,362,526	19,101,030
CWIP in Service Pending Reclassification	264,640		
Total Gas Plant in Service	16,318,993	16,362,526	19,101,030
Additions			
Materials and Supplies	290,358	253,531	253,531
Prepayments	50,818	48,803	55,121
Other	174,494	166,563	150,699
Total Additions	515,670	468,897	459,351
Total Before Deductions	$16,834,663	$16,831,423	$19,560,381
Deductions			
Accumulated Deferred Income Taxes	$1,840,886	$1,786,289	$1,667,062
Accumulated Investment Tax Credits	39,658	33,248	18,324
Customer Advances	124,337	90,063	81,227
Total Deductions	2,004,881	1,909,600	1,766,613
Total Rate Base	$14,829,782	$14,921,823	$17,793,768

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - SOUTH DAKOTA

	2003 Before Additional Revenue Requirements	**Additional Revenue Requirements**	Pro Forma Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$36,834,005	**$2,173,724**	$39,007,729
Transportation	352,589		352,589
Other	147,425		147,425
Total Revenues	37,334,019	2,173,724	39,507,743
Operating Expenses			
Operation and Maintenance			
Cost of Gas	26,946,077		26,946,077
Other O&M	7,292,809		7,292,809
Total O&M	34,238,886		34,238,886
Depreciation	1,837,574		1,837,574
Taxes Other Than Income	775,067	3,261	778,328
Current Income Taxes	(620,957)	760,803	139,846
Deferred Income Taxes	679,817		679,817
Total Expenses	36,910,387	764,064	37,674,451
Operating Income	$423,632	$1,409,660	$1,833,292
Rate Base	$17,793,768		$17,793,768
Rate of Return	**2.381%**		**10.303%**

DOCKET NO. ____
RULE 20:10:13:97
STATEMENT N

CLASS COST OF SERVICE STUDY

Part A – Reports

Part B – Allocation Assignment Report

Part C – Allocation Factor Report

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENT

Cost of Service By Component	Total South Dakota	Residential Demand	Residential Energy	Residential Customer	Firm General Demand	Firm General Energy	Firm General Customer
Projected Rate Base	17,793,766	3,785,615	1,528	8,015,481	2,400,745	1,043	2,995,685
Operating Income for Proposed Return	1,833,290	390,032	157	825,835	247,349	107	308,645
Projected Operating Income	423,630	(737,672)	2,628,683	(1,646,325)	(467,800)	1,198,959	(805,451)
Increase in Operating Income	1,409,660	1,127,704	(2,628,526)	2,472,160	715,149	(1,198,852)	1,114,096
Related Taxes for Increase							
Federal Income	760,801	608,630	(1,418,634)	1,334,242	385,971	(647,029)	601,285
South Dakota Gross Receipts Tax	3,260	2,608	(6,080)	5,718	1,654	(2,773)	2,577
Total Increase in Revenue	2,173,721	1,738,942	(4,053,240)	3,812,120	1,102,774	(1,848,654)	1,717,958
Projected Revenues before Increase	37,334,015	4,479,171	13,094,425	3,088,930	3,056,399	8,022,460	582,598
Total Cost of Service Required From Rates	39,507,736	6,218,113	9,041,185	6,901,050	4,159,173	6,173,806	2,300,556
Less Projected Cost of Gas	26,946,077	4,454,625	8,974,478	0	3,040,810	6,126,151	0
Net Distribution Costs	12,561,659	1,763,488	66,707	6,901,050	1,118,363	47,655	2,300,556
Billing Units at Customer							
Dk Throughput		3,151,151	3,151,151	0	2,151,036	2,151,036	0
Bills		0	0	430,092	0	0	58,560
Unit Cost of Service							
$ Per Dk		0.560	0.021	0.000	0.520	0.022	0.000
$ Per Customer Per Month		0.000	0.000	16.046	0.000	0.000	39.285

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENT

	Firm Contract			Air Force		
Cost of Service By Component	Demand	Energy	Customer	Demand	Energy	Customer
Projected Rate Base	114,552	303	17,817	0	276	20,703
Operating Income for Proposed Return	11,802	31	1,836	0	28	2,133
Projected Operating Income	(22,320)	135,821	(244)	15	14,143	(330)
Increase in Operating Income	34,122	(135,790)	2,080	(15)	(14,115)	2,463
Related Taxes for Increase						
Federal Income	18,416	(73,287)	1,122	(8)	(7,618)	1,329
South Dakota Gross Receipts Tax	79	(314)	5	0	(33)	6
Total Increase in Revenue	52,617	(209,391)	3,207	(23)	(21,766)	3,798
Projected Revenues before Increase	192,757	2,247,658	1,910	227,342	1,524,712	1,263
Total Cost of Service Required From Rates	245,374	2,038,267	5,117	227,319	1,502,946	5,061
Less Projected Cost of Gas	192,010	2,023,646	0	227,318	1,489,245	0
Net Distribution Costs	53,364	14,621	5,117	1	13,701	5,061
Billing Units at Customer						
Dk Throughput	625,741	625,741	0	569,719	569,719	0
Bills	0	0	12	0	0	12
Unit Cost of Service						
$ Per Dk	0.085	0.023	0.000	0.000	0.024	0.000
$ Per Customer Per Month	0.000	0.000	426.417	0.000	0.000	421.750

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
COST OF SERVICE BY COMPONENT

	Small Interruptible			Large Interruptible		
Cost of Service By Component	Demand	Energy	Customer	Demand	Energy	Customer
Projected Rate Base	60,284	71	201,579	93,701	136	84,247
Operating Income for Proposed Return	6,211	7	20,769	9,654	14	8,680
Projected Operating Income	(11,748)	120,964	(42,543)	(18,261)	81,991	(4,252)
Increase in Operating Income	17,959	(120,957)	63,312	27,915	(81,977)	12,932
Related Taxes for Increase						
Federal Income	9,692	(65,281)	34,170	15,065	(44,243)	6,979
South Dakota Gross Receipts Tax	42	(280)	146	65	(190)	30
Total Increase in Revenue	27,693	(186,518)	97,628	43,045	(126,410)	19,941
Projected Revenues before Increase	55,183	300,121	41,025	35,938	350,340	31,783
Total Cost of Service Required From Rates	82,876	113,603	138,653	78,983	223,930	51,724
Less Projected Cost of Gas	54,793	110,388	0	35,337	217,276	0
Net Distribution Costs	28,083	3,215	138,653	43,646	6,654	51,724
Billing Units at Customer						
Dk Throughput	403,210	403,210	0	747,790	747,790	0
Bills	0	0	504	0	0	132
Unit Cost of Service						
$ Per Dk	0.070	0.008	0.000	0.058	0.009	0.000
$ Per Customer Per Month	0.000	0.000	275.105	0.000	0.000	391.848

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
SUMMARY REPORT
PROJECTED 2003

Projected Operating Income and Rate of Return	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Operating Revenues	37,334,015	20,662,526	11,661,457	2,442,325	1,753,317	396,329	418,061
Operating Expenses							
O&M Cost of Purchased Gas	26,946,077	13,429,103	9,166,961	2,215,656	1,716,563	165,181	252,613
Other O&M Expense	7,292,805	5,211,425	1,880,501	36,829	13,521	94,817	55,712
Total Operation & Maint. Exp.	34,238,882	18,640,528	11,047,462	2,252,485	1,730,084	259,998	308,325
Depreciation	1,837,570	1,220,425	564,179	12,167	1,073	25,998	13,728
Taxes Other Than Income Taxes	775,068	533,180	219,090	4,853	1,063	10,432	6,450
Fed. & State Inc. Taxes - Current	(620,950)	(281,485)	(324,559)	(25,301)	(43,719)	30,281	23,833
Deferred Income Taxes	679,815	305,192	229,577	84,864	50,988	2,947	6,247
Total Operating Expenses	36,910,385	20,417,840	11,735,749	2,329,068	1,739,489	329,656	358,583
Operating Income	423,630	244,686	(74,292)	113,257	13,828	66,673	59,478
Rate Base	17,793,766	11,802,624	5,397,473	132,672	20,979	261,934	178,084
Rate of Return	2.381%	2.073%	-1.376%	85.366%	65.914%	25.454%	33.399%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
RATE BASE REPORT
PROJECTED 2003

Projected Rate Base	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Gas Plant in Service	43,732,811	29,062,170	13,316,761	319,149	38,749	604,883	391,099
Less: Accumulated Depreciation	24,631,780	16,434,493	7,475,528	177,198	16,839	325,871	201,851
Net Gas Plant in Service	19,101,031	12,627,677	5,841,233	141,951	21,910	279,012	189,248
CWIP in Service	0	0	0	0	0	0	0
Total Plant	19,101,031	12,627,677	5,841,233	141,951	21,910	279,012	189,248
Additions							
Materials & Supplies	253,529	168,481	77,201	1,849	224	3,506	2,268
Unamortized Gas IRP Costs - Other	165,694	118,346	42,763	845	318	2,160	1,262
Prepaid Insurance	40,126	25,881	12,952	327	20	566	380
Total Additions	459,349	312,708	132,916	3,021	562	6,232	3,910
Total Before Deductions	19,560,380	12,940,385	5,974,149	144,972	22,472	285,244	193,158
Deductions							
Accumulated Deferred Income Tax	(1,667,062)	(1,107,828)	(507,625)	(12,165)	(1,477)	(23,058)	(14,909)
Investment Tax Credit Balance	(18,324)	(12,177)	(5,580)	(134)	(16)	(252)	(165)
Customer Advances For Constr.	(81,228)	(17,756)	(63,471)	(1)	0	0	0
Total Deductions	(1,766,614)	(1,137,761)	(576,676)	(12,300)	(1,493)	(23,310)	(15,074)
Total Rate Base	17,793,766	11,802,624	5,397,473	132,672	20,979	261,934	178,084

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
SUMMARY REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Operating Income and Rate of Return	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Operating Revenues	31,494,699	17,180,417	9,441,727	2,664,567	1,353,999	430,095	423,894
Operating Expenses							
Cost of Gas	21,351,949	10,383,254	7,087,808	2,230,621	1,327,230	127,717	195,319
Other O&M Expense	6,262,737	4,471,507	1,617,802	31,993	11,995	81,680	47,760
Total Operation & Maint. Exp.	27,614,686	14,854,761	8,705,610	2,262,614	1,339,225	209,397	243,079
Depreciation	1,607,616	1,067,612	494,158	10,489	869	22,817	11,671
Taxes Other Than Income Taxes	719,996	494,928	203,865	4,526	980	9,696	6,001
Fed. & State Inc. Taxes - Current	546,060	243,889	17,253	149,918	13,694	64,476	56,830
Deferred Income Taxes	(107,221)	(22,869)	(39,250)	(27,765)	(17,261)	799	(875)
Total Operating Expenses	30,381,137	16,638,321	9,381,636	2,399,782	1,337,507	307,185	316,706
Operating Income	1,113,562	542,096	60,091	264,785	16,492	122,910	107,188
Rate Base	16,886,225	11,197,048	5,123,183	126,126	20,204	249,580	170,084
Rate of Return	6.594%	4.841%	1.173%	209.937%	81.627%	49.247%	63.021%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PLANT IN SERVICE
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Plant in Service	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Distribution Plant							
Mains	17,449,998	12,077,434	4,900,368	198,357	0	110,269	163,570
Structures & Improvements	37,324	22,566	9,156	370	4,720	206	306
Meas. & Reg. Sta. Eqpt. - General	243,980	165,103	72,422	2,711	0	1,508	2,236
Meas. & Reg. Sta. Eqpt. - City Gate	58,623	0	0	0	18,848	4,920	34,855
Service Regulators	822,060	505,226	280,111	0	0	27,598	9,125
Indust. Meas. & Reg. Sta. Eqpt.	63,429	0	0	0	0	7,846	55,583
Services	5,231,490	3,306,619	1,800,876	0	0	123,995	0
Meters	5,815,113	3,666,640	1,996,953	14,025	0	137,495	0
CNG Refueling Station	170,931	118,305	48,001	1,943	0	1,080	1,602
Cathodic Protection & Other Equipment	152,587	103,472	41,983	1,699	3,087	945	1,401
Land & Land Rights	38,914	26,933	10,928	442	0	246	365
Total Distribution Plant	30,084,449	19,992,298	9,160,798	219,547	26,655	416,108	269,043
General Plant	9,132,626	6,068,988	2,780,909	66,647	8,092	126,317	81,673
Common Plant	2,223,009	1,477,276	676,912	16,223	1,970	30,748	19,880
Gas Plant Leased to Others	0	0	0	0	0	0	0
Total Gas Plant in Service	41,440,084	27,538,562	12,618,619	302,417	36,717	573,173	370,596

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ACCUMULATED RESERVE FOR DEPRECIATION
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Accumulated Reserve for Depreciation	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Distribution Plant							
Mains	12,423,374	8,598,424	3,488,774	141,219	0	78,505	116,452
Structures & Improvements	9,973	6,029	2,447	99	1,261	55	82
Meas. & Reg. Sta. Equip. - General	105,319	71,270	31,262	1,170	0	651	966
Meas. & Reg. Sta. Equip. - City Gate	36,275	0	0	0	11,663	3,044	21,568
Services	4,925,117	3,112,973	1,695,411	0	0	116,733	0
Meters	2,150,241	1,359,083	740,194	0	0	50,964	0
Service Regulators	326,174	200,462	111,141	0	0	10,950	3,621
Indust. Meas. & Reg. Sta. Eqpt.	20,104	0	0	0	0	2,487	17,617
Other Property on Customer Prem.	129,298	89,489	36,310	1,470	0	817	1,212
Cathodic Protection & Other Equipment	82,526	57,118	23,175	938	0	521	774
Land Rights	4,958	3,432	1,392	56	0	32	46
Total Distribution Reserve	20,213,359	13,498,280	6,130,106	144,952	12,924	264,759	162,338
General Plant	2,231,366	1,482,830	679,457	16,284	1,977	30,863	19,955
Common Plant	945,104	628,059	287,787	6,897	837	13,072	8,452
Gas Plant Leased to Others	(92)	(61)	(28)	(1)	0	(1)	(1)
Total Accumulated Reserve for Depreciation	23,389,737	15,609,108	7,097,322	168,132	15,738	308,693	190,744

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STATEMENT N
PART A
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MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
CONSTRUCTION WORK IN PROGRESS
TWELVE MONTHS ENDED JUNE 30, 2002

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	264,640	175,864	80,583	1,931	234	3,661	2,367
Total Construction Work in Progress in Service Pending Classification	264,640	175,864	80,583	1,931	234	3,661	2,367

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATING REVENUES
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Operating Revenues	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Residential	16,986,636	16,986,636	0	0	0	0	0
Firm General	9,351,016	0	9,351,016	0	0	0	0
Firm Contract	2,649,192	0	0	2,649,192	0	0	0
Air Force	1,346,470	0	0	0	1,346,470	0	0
Small Interruptible	425,970	0	0	0	0	425,970	0
Large Interruptible	420,398	0	0	0	0	0	420,398
Unbilled Revenue	167,596	91,307	50,263	14,239	7,238	2,289	2,260
Total Gas Sales and Transport Revenue	31,347,278	17,077,943	9,401,279	2,663,431	1,353,708	428,259	422,658
Other Operating Revenue							
Miscellaneous							
Reconnect Fees	8,965	7,891	1,074	0	0	0	0
NSF Check Fees	10,720	9,435	1,285	0	0	0	0
Work for Contractors, Municipal & Others	20,084	13,275	6,143	149	23	294	200
Energy Diversion	46	31	14	0	0	1	0
CNG Compression & O&M Charges	0	0	0	0	0	0	0
Rent From Gas Property	84,273	55,696	25,778	627	98	1,235	839
Other Gas Revenues							
Miscellaneous	20,310	14,500	5,247	104	39	265	155
Transport and Penalty Revenue - Net	3,023	1,646	907	256	131	41	42
Total Other Operating Revenue	147,421	102,474	40,448	1,136	291	1,836	1,236
Total Gas Operating Revenues	31,494,699	17,180,417	9,441,727	2,664,567	1,353,999	430,095	423,894

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATION & MAINTENANCE EXPENSES
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Operation and Maintenance Expenses	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Cost of Purchased Gas	21,351,949	10,383,254	7,087,808	2,230,621	1,327,230	127,717	195,319
Production Expenses							
Other Gas Supply Expenses	64,321	30,619	20,901	6,080	5,536	377	808
Total Production Expense	64,321	30,619	20,901	6,080	5,536	377	808
Distribution Expenses							
Operation							
Load Dispatch	31,454	12,959	8,846	2,573	2,343	1,658	3,075
Mains and Services	722,091	489,772	213,343	6,310	0	7,459	5,207
Measuring Stations - General	5,969	4,040	1,772	66	0	37	54
Measuring Stations - Industrial	5,896	0	0	0	0	729	5,167
Measuring Stations - City Gate	48	0	0	0	15	4	29
Meters & House Regulators	240,930	151,439	82,658	509	0	5,993	331
Customer Installations	435,155	275,044	149,797	0	0	10,314	0
Other Gas Distribution	529,606	345,647	168,100	2,586	6	9,215	4,052
Rents	32,909	21,478	10,446	161	0	572	252
Supervision & Engineering	391,212	255,325	124,173	1,910	4	6,807	2,993
Total Operation Expense	2,395,270	1,555,704	759,135	14,115	2,368	42,788	21,160
Maintenance							
Structures & Improvements	2,348	1,420	576	23	297	13	19
Mains	55,969	38,736	15,717	637	0	354	525
Measuring Stations - General	6,203	4,197	1,842	69	0	38	57
Measuring Stations - Industrial	4,624	0	0	0	0	572	4,052
Measuring Stations - City Gate	0	0	0	0	0	0	0
Services	29,333	18,247	9,859	60	0	630	537
Meters & House Regulators	42,708	26,845	14,652	90	0	1,062	59
Other Equipment	72,107	45,717	21,850	444	0	1,380	2,716
Supervision & Engineering	66,326	42,052	20,098	409	0	1,269	2,498
Total Maintenance Expense	279,618	177,214	84,594	1,732	297	5,318	10,463

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
OPERATION & MAINTENANCE EXPENSES
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Operation and Maintenance Expenses	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Total Distribution Expenses	2,674,888	1,732,918	843,729	15,847	2,665	48,106	31,623
Customer Accounts	80,928	71,134	9,685	2	2	83	22
Meter Reading	263,402	166,486	90,673	0	0	6,243	0
Customer Records & Collection	724,756	637,040	86,737	18	18	747	196
Uncollectible Accounts	81,449	71,591	9,748	2	2	84	22
Miscellaneous Customer Accounts	92,670	81,455	11,091	2	2	95	25
Customer Service & Information	63,687	55,978	7,622	2	2	66	17
Sales Expenses	252,370	221,827	30,203	6	6	260	68
Administration & General Expenses	1,964,266	1,402,459	507,413	10,034	3,762	25,619	14,979
Total Gas O&M Expenses	27,614,686	14,854,761	8,705,610	2,262,614	1,339,225	209,397	243,079
O&M Excl. Gas Cost and A&G	4,298,471	3,069,048	1,110,389	21,959	8,233	56,061	32,781
O&M Excl. Cost of Gas	6,262,737	4,471,507	1,617,802	31,993	11,995	81,680	47,760

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
DEPRECIATION EXPENSE
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Depreciation Expense	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Distribution Plant							
Mains	718,378	497,201	201,737	8,166	0	4,540	6,734
Structures	895	542	219	9	113	5	7
Meas. & Reg. Sta. General	5,552	3,758	1,648	62	0	34	50
Meas. & Reg. Sta. - City Gate	1,606	0	0	0	516	135	955
Services	419,675	265,260	144,468	0	0	9,947	0
Meters	145,917	92,229	50,230	0	0	3,458	0
Service Regulators	19,288	11,854	6,572	0	0	648	214
Measuring & Reg. Eqpt. - Indust.	1,211	0	0	0	0	150	1,061
Other Property on Cust. Prem.	15,982	11,062	4,488	182	0	101	149
Cathodic Protection & Other Equipment	7,950	5,502	2,232	90	0	51	75
Land Rights	221	153	62	3	0	1	2
Total Distribution Plant	1,336,675	887,561	411,656	8,512	629	19,070	9,247
General Plant	113,595	75,488	34,590	829	101	1,571	1,016
Common Plant	157,346	104,563	47,912	1,148	139	2,176	1,408
Gas Plant Leased to Others	0	0	0	0	0	0	0
Total Depreciation Expense	1,607,616	1,067,612	494,158	10,489	869	22,817	11,671

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
TAXES OTHER THAN INCOME TAXES
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Taxes Other Than Income	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Ad Valorem Taxes	387,047	257,208	117,857	2,825	343	5,353	3,461
Other Taxes - Payroll, Franchise, Other	332,949	237,720	86,008	1,701	637	4,343	2,540
Total Taxes Other Than Income	719,996	494,928	203,865	4,526	980	9,696	6,001

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
DEFERRED INCOME TAXES
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Deferred Income Taxes	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Management Incentive Compensation	(11,356)	(7,547)	(3,458)	(83)	(10)	(157)	(101)
Pension Expense	119,532	79,434	36,398	872	106	1,653	1,069
Sundry Reserves	1,110	737	338	9	1	15	10
Reserve For Deferred Maintenance	1,036	689	315	7	1	15	9
Property Insurance Adjustment	(3,902)	(2,593)	(1,188)	(29)	(3)	(54)	(35)
Bad Debt Expense	17,665	9,623	5,298	1,501	763	242	238
Accrued Vacation	9,307	6,646	2,404	48	18	121	70
Capitalized Overheads	(63,090)	(41,925)	(19,211)	(461)	(56)	(873)	(564)
Customer Advances	335	295	40	0	0	0	0
Restricted Stock Bonus Plan	9,450	6,747	2,440	49	18	123	73
FAS 106 - OPRB	5,565	3,972	1,438	29	10	73	43
Deferred Compensation - Directors	(2,896)	(2,068)	(748)	(15)	(5)	(37)	(23)
Board of Directors - Retirement Benefits	(44,823)	(32,004)	(11,579)	(228)	(86)	(585)	(341)
Demand Charges	4,470	2,548	1,637	76	69	49	91
PCB Related Income	(1,294)	(860)	(394)	(10)	(1)	(18)	(11)
Liberalized Deprec. & Oth. Prop. Tim. Diff.	(38,841)	(25,812)	(11,827)	(283)	(34)	(538)	(347)
Unrecovered Purchased Gas Costs	(292,848)	(142,410)	(97,211)	(30,594)	(18,203)	(1,751)	(2,679)
Rate Case Expense	0	0	0	0	0	0	0
Amort. of Loss on Bond Retirements	(23,033)	(15,223)	(7,046)	(171)	(27)	(337)	(229)
FAS 106 Deferred Expense	(5,552)	(3,963)	(1,434)	(29)	(10)	(73)	(43)
Gas IRP	0	0	0	0	0	0	0
Closing/Filing and Out of Period	211,944	140,845	64,538	1,547	188	2,931	1,895
Total Gas Charges	(107,221)	(22,869)	(39,250)	(27,765)	(17,261)	799	(875)
Accumulated Balance 6/30/02	(1,821,350)	(1,210,359)	(554,606)	(13,291)	(1,614)	(25,192)	(16,288)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
INCOME TAXES
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Income Taxes	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Operating Revenue	31,494,699	17,180,417	9,441,727	2,664,567	1,353,999	430,095	423,894
Operation & Maintenance Expense	27,614,686	14,854,761	8,705,610	2,262,614	1,339,225	209,397	243,079
Depreciation Expense	1,607,616	1,067,612	494,158	10,489	869	22,817	11,671
Taxes Other Than Income	719,996	494,928	203,865	4,526	980	9,696	6,001
Total Operating Expense	29,942,298	16,417,301	9,403,633	2,277,629	1,341,074	241,910	260,751
Interest Expense	690,970	456,662	211,357	5,140	803	10,124	6,884
Total Expenses	30,633,268	16,873,963	9,614,990	2,282,769	1,341,877	252,034	267,635
Taxable Income Before Adjustments	861,431	306,454	(173,263)	381,798	12,122	178,061	156,259
Tax Deductions							
Management Incentive Compensation	(32,446)	(21,562)	(9,880)	(236)	(29)	(449)	(290)
Pension Expense	341,524	226,956	103,995	2,492	303	4,724	3,054
Sundry Reserves	3,171	2,107	966	23	3	43	29
Reserve For Deferred Maintenance	3,061	2,035	932	22	3	42	27
Property Insurance Adjustment	(11,148)	(7,409)	(3,395)	(81)	(10)	(154)	(99)
Bad Debt Expense	50,466	27,494	15,135	4,288	2,179	689	681
Accrued Vacation	26,600	18,992	6,872	136	51	347	202
Capitalized Overheads	(180,254)	(119,786)	(54,887)	(1,315)	(160)	(2,494)	(1,612)
Customer Advances	957	842	115	0	0	0	0
Restricted Stock Bonus Plan	26,999	19,279	6,975	137	51	352	205
FAS 106 - OPRB	15,896	11,350	4,106	81	30	208	121
Deferred Compensation-Directors	(8,277)	(5,910)	(2,138)	(42)	(16)	(108)	(63)
Board of Directors - Retirement Benefits	(128,073)	(91,442)	(33,083)	(654)	(246)	(1,671)	(977)
Demand Charges	12,771	7,279	4,676	218	198	140	260
PCB Related Income	(9,862)	(6,554)	(3,003)	(72)	(9)	(136)	(88)
Plant Reclassification	17,187	11,421	5,234	125	15	238	154
Liberalized Depreciation & OPTD	(499,965)	(332,245)	(152,241)	(3,649)	(443)	(6,915)	(4,472)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
INCOME TAXES
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Income Taxes	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Contributions in Aid of Construction	(705)	(468)	(215)	(5)	(1)	(10)	(6)
Purchased Gas Cost Adjustment	(836,713)	(406,885)	(277,748)	(87,411)	(52,010)	(5,005)	(7,654)
Amort. of Loss on Bond Retirements	(65,810)	(43,494)	(20,131)	(489)	(76)	(964)	(656)
FAS 106 - Deferred Expense	(15,864)	(11,326)	(4,098)	(81)	(30)	(208)	(121)
Gas IRP	0	0	0	0	0	0	0
Disallowed Meals & Entertainment	(14,215)	(10,148)	(3,672)	(73)	(27)	(186)	(109)
Federal Non-Hwy. Use Tax Credit	(2,700)	(1,795)	(822)	(19)	(2)	(38)	(24)
Preferred Dividend Paid Deduction	8,065	5,359	2,456	59	7	112	72
Total Deductions & Adjustments	(1,299,335)	(725,910)	(413,851)	(86,546)	(50,219)	(11,443)	(11,366)
Taxable Income (Before State Income Tax)	2,160,766	1,032,364	240,588	468,344	62,341	189,504	167,625
Less: State Income Tax	0	0	0	0	0	0	0
Federal Taxable Income	2,160,766	1,032,364	240,588	468,344	62,341	189,504	167,625
Federal Income Tax @ Current Rate	756,268	361,327	84,206	163,920	21,819	66,327	58,669
Plus: State Income Tax	0	0	0	0	0	0	0
Plus: Credits & Adjustments	(210,208)	(117,438)	(66,953)	(14,002)	(8,125)	(1,851)	(1,839)
Federal and State Income Taxes	546,060	243,889	17,253	149,918	13,694	64,476	56,830
Rounding & Prior Year Adjustments	0	0	0	0	0	0	0
Federal Income Tax Computed	546,060	243,889	17,253	149,918	13,694	64,476	56,830

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
WORKING CAPITAL
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Working Capital	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Materials & Supplies	299,633	199,119	91,239	2,186	265	4,144	2,680
Prepaid Insurance	55,991	37,208	17,050	408	50	774	501
Unamortized Gas IRP Costs - Other	166,563	118,924	43,027	851	319	2,172	1,270

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
RATE BASE REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

Per Books Rate Base	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Gas Plant in Service	41,440,084	27,538,562	12,618,619	302,417	36,717	573,173	370,596
Less: Accumulated Depreciation	23,389,737	15,609,108	7,097,322	168,132	15,738	308,693	190,744
Net Gas Plant in Service	18,050,347	11,929,454	5,521,297	134,285	20,979	264,480	179,852
CWIP in Service	264,640	175,864	80,583	1,931	234	3,661	2,367
Total Plant	18,314,987	12,105,318	5,601,880	136,216	21,213	268,141	182,219
Additions							
Materials & Supplies	299,633	199,119	91,239	2,186	265	4,144	2,680
Unamortized Gas IRP Costs - Other	166,563	118,924	43,027	851	319	2,172	1,270
Prepaid Insurance	55,991	37,208	17,050	408	50	774	501
Total Additions	522,187	355,251	151,316	3,445	634	7,090	4,451
Total Before Deductions	18,837,174	12,460,569	5,753,196	139,661	21,847	275,231	186,670
Deductions							
Accumulated Deferred Income Tax	(1,821,350)	(1,210,359)	(554,606)	(13,291)	(1,614)	(25,192)	(16,288)
Investment Tax Credit Balance	(33,248)	(22,095)	(10,124)	(243)	(29)	(459)	(298)
Customer Advances For Constr.	(96,351)	(31,067)	(65,283)	(1)	0	0	0
Total Deductions	(1,950,949)	(1,263,521)	(630,013)	(13,535)	(1,643)	(25,651)	(16,586)
Total Rate Base	16,886,225	11,197,048	5,123,183	126,126	20,204	249,580	170,084

MONTANA-DAKOTA UTILITIES
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PROJECTED CHANGES IN OPERATING INCOME

Projected Changes in Operating Income	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Revenue @ Current Rates							
Sales Revenue	6,006,912	3,573,416	2,269,993	(208,003)	406,556	(31,477)	(3,573)
Unbilled Revenue	(167,596)	(91,307)	(50,263)	(14,239)	(7,238)	(2,289)	(2,260)
Total Revenue	5,839,316	3,482,109	2,219,730	(222,242)	399,318	(33,766)	(5,833)
Cost of Gas	5,594,128	3,045,849	2,079,153	(14,965)	389,333	37,464	57,294
Labor Expense							
Other Gas Supply	7,232	5,163	1,868	37	14	94	56
Distribution	235,808	152,768	74,380	1,397	235	4,240	2,788
Customer Accounts	104,959	92,255	12,561	3	3	108	29
Customer Service & Information	4,866	4,278	582	0	0	5	1
Sales	24,339	21,392	2,913	1	1	25	7
Administrative & General	84,987	60,680	21,954	434	163	1,108	648
Total Labor Expense	462,191	336,536	114,258	1,872	416	5,580	3,529
Benefits Expense	403,447	288,056	104,219	2,061	773	5,262	3,076
Insurance Expense	54,700	39,055	14,131	279	105	713	417
Advertising Expense	(22,099)	(19,423)	(2,645)	(1)	(1)	(23)	(6)
Postage Expense	9,511	8,360	1,138	0	0	10	3
Industry Dues	1,893	1,352	489	10	3	25	14
Rate Case Expense	17,838	12,737	4,608	91	34	232	136
All Other O&M	102,587	73,245	26,501	524	196	1,338	783
Total Other O&M	1,030,068	739,918	262,699	4,836	1,526	13,137	7,952
Depreciation Expense	229,954	152,813	70,021	1,678	204	3,181	2,057

MONTANA-DAKOTA UTILITIES
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PROJECTED CHANGES IN OPERATING INCOME

Projected Changes in Operating Income	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Taxes Other than Income							
Ad Valorem Tax	21,598	14,352	6,577	157	19	299	194
Other Taxes - Payroll, Franchise, Other	33,474	23,900	8,648	170	64	437	255
Total Taxes Other than Income	55,072	38,252	15,225	327	83	736	449
Current Income Tax							
Interest Expense	26,650	17,613	8,152	198	31	390	266
Other Tax Deductions							
Management Incentive Compensation	32,446	21,562	9,880	236	29	449	290
Pension Expense	(237,623)	(157,909)	(72,357)	(1,734)	(211)	(3,287)	(2,125)
Sundry Reserves	(3,171)	(2,107)	(966)	(23)	(3)	(43)	(29)
Reserve for Deferred Maintenance	(3,061)	(2,035)	(932)	(22)	(3)	(42)	(27)
Property Insurance Adjustment	11,148	7,409	3,395	81	10	154	99
Bad Debt Expense	(50,466)	(27,494)	(15,135)	(4,288)	(2,179)	(689)	(681)
Accrued Vacation	(26,600)	(18,992)	(6,872)	(136)	(51)	(347)	(202)
Capitalized Overheads	180,254	119,786	54,887	1,315	160	2,494	1,612
Customer Advances	(957)	(842)	(115)	0	0	0	0
Restricted Stock Bonus Plan	(26,999)	(19,279)	(6,975)	(137)	(51)	(352)	(205)
FAS 106-OPRB	(98,788)	(70,533)	(25,519)	(505)	(189)	(1,289)	(753)
Deferred Compensation - Directors	8,277	5,910	2,138	42	16	108	63
BOD Retirement Benefits	128,073	91,442	33,083	654	246	1,671	977
Demand Charges	(12,771)	(7,279)	(4,676)	(218)	(198)	(140)	(260)
PCB Related Income	9,862	6,554	3,003	72	9	136	88
Plant Reclassification	(17,187)	(11,421)	(5,234)	(125)	(15)	(238)	(154)
Liberalized Depreciation & Other	(220,263)	(146,373)	(67,071)	(1,608)	(195)	(3,046)	(1,970)
Contributions in Aid of Construction	705	468	215	5	1	10	6
Purchased Gas Cost Adjustment	3,186,103	1,549,373	1,057,632	332,849	198,047	19,057	29,145
Amortization of Loss on Bond Retirements	(16,764)	(11,079)	(5,128)	(125)	(19)	(246)	(167)
FAS 106 Deferred Expense	(1)	(1)	0	0	0	0	0
Meals & Entertainment	(6,558)	(4,682)	(1,694)	(33)	(13)	(86)	(50)
Federal Nonhwy Use Tax Credit	2,700	1,795	822	19	2	38	24
Total Other Income Tax Deductions	2,838,359	1,324,273	952,381	326,319	195,393	14,312	25,681

MONTANA-DAKOTA UTILITIES
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PROJECTED CHANGES IN OPERATING INCOME

Projected Changes in Operating Income	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Deferred Income Taxes							
Management Incentive Compensation	11,356	7,547	3,458	83	10	157	101
Pension Expense	(146,633)	(97,443)	(44,650)	(1,070)	(130)	(2,028)	(1,312)
Sundry Reserves	(1,110)	(737)	(338)	(9)	(1)	(15)	(10)
Reserve for Deferred Maintenance	(1,036)	(689)	(315)	(7)	(1)	(15)	(9)
Property Insurance Adjustment	3,902	2,593	1,188	29	3	54	35
Bad Debt Expense	(17,665)	(9,623)	(5,298)	(1,501)	(763)	(242)	(238)
Accrued Vacation	(9,307)	(6,646)	(2,404)	(48)	(18)	(121)	(70)
Capitalized Overheads	63,090	41,925	19,211	461	56	873	564
Customer Advances	(335)	(295)	(40)	0	0	0	0
Restricted Stock Bonus Plan	(9,450)	(6,747)	(2,440)	(49)	(18)	(123)	(73)
FAS 106	(5,565)	(3,972)	(1,438)	(29)	(10)	(73)	(43)
Deferred Compensation - Directors	2,896	2,068	748	15	5	37	23
BOD Retirement Benefits	44,823	32,004	11,579	228	86	585	341
Demand Charges	(4,470)	(2,548)	(1,637)	(76)	(69)	(49)	(91)
PCB Related Income	1,294	860	394	10	1	18	11
Liberalized Deprec. & Other Prop Timing Diff	(76,530)	(50,857)	(23,304)	(558)	(68)	(1,059)	(684)
Unrecovered Purchased Gas Cost	1,115,135	542,280	370,171	116,497	69,317	6,670	10,200
Amort of Loss on Bond Retirements	23,033	15,223	7,046	171	27	337	229
FAS 106 Deferred Expense	5,552	3,963	1,434	29	10	73	43
Closing/Filing and Out of Period	(211,944)	(140,845)	(64,538)	(1,547)	(188)	(2,931)	(1,895)
Total Deferred Income Tax	787,036	328,061	268,827	112,629	68,249	2,148	7,122

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PROJECTED FEDERAL STATE INCOME TAXES

Projected Federal & State Income Taxes	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Projected Operating Revenues	37,334,015	20,662,526	11,661,457	2,442,325	1,753,317	396,329	418,061
Projected Operating Expenses							
Cost of Gas	26,946,077	13,429,103	9,166,961	2,215,656	1,716,563	165,181	252,613
Other O&M Expense	7,292,805	5,211,425	1,880,501	36,829	13,521	94,817	55,712
Total Operation & Maint. Exp.	34,238,882	18,640,528	11,047,462	2,252,485	1,730,084	259,998	308,325
Projected Depreciation	1,837,570	1,220,425	564,179	12,167	1,073	25,998	13,728
Projected Taxes Other	775,068	533,180	219,090	4,853	1,063	10,432	6,450
Total Projected Operating Expense	36,851,520	20,394,133	11,830,731	2,269,505	1,732,220	296,428	328,503
Projected Operating Income Before Taxes	482,495	268,393	(169,274)	172,820	21,097	99,901	89,558
Projected Interest Expense	717,620	474,275	219,509	5,338	834	10,514	7,150
Preferred Dividend Deduction	8,065	5,359	2,456	59	7	112	72
Projected Other Tax Deductions	1,530,959	593,004	536,074	239,714	145,167	2,757	14,243
Projected Taxable Income	(1,774,149)	(804,245)	(927,313)	(72,291)	(124,911)	86,518	68,093
Projected Federal & State Income Taxes	(620,950)	(281,485)	(324,559)	(25,301)	(43,719)	30,281	23,833

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
PROJECTED CHANGES IN RATE BASE

Projected Changes in Rate Base	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Plant in Service							
Distribution Plant	1,788,388	1,188,454	544,569	13,052	1,585	24,735	15,993
General Plant	60,525	40,221	18,430	442	54	837	541
Common Plant	443,814	294,933	135,143	3,238	393	6,138	3,969
Total Plant	2,292,727	1,523,608	698,142	16,732	2,032	31,710	20,503
Accumulated Reserve							
Distribution Plant	1,294,588	860,305	394,206	9,448	1,147	17,905	11,577
General Plant	(117,536)	(78,109)	(35,790)	(857)	(104)	(1,625)	(1,051)
Common Plant	64,991	43,189	19,790	475	58	898	581
Total Accumulated Res	1,242,043	825,385	378,206	9,066	1,101	17,178	11,107
Elimination of CWIP in Service	(264,640)	(175,864)	(80,583)	(1,931)	(234)	(3,661)	(2,367)
Additions to Rate Base:							
Materials & Supplies	(46,104)	(30,638)	(14,038)	(337)	(41)	(638)	(412)
Prepayments	(869)	(578)	(264)	(6)	(1)	(12)	(8)
Unamortized FAS 106 Costs - Other	(15,865)	(11,327)	(4,098)	(81)	(30)	(208)	(121)
Total Additions	(62,838)	(42,543)	(18,400)	(424)	(72)	(858)	(541)
Deductions to Rate Base:							
Accumulated Deferred Income Taxes	(154,288)	(102,531)	(46,981)	(1,126)	(137)	(2,134)	(1,379)
Accumulated Investment Tax Credits	(14,924)	(9,918)	(4,544)	(109)	(13)	(207)	(133)
Customer Advances	(15,123)	(13,311)	(1,812)	0	0	0	0
Total Adjustments	(184,335)	(125,760)	(53,337)	(1,235)	(150)	(2,341)	(1,512)
Total Rate Base	907,541	605,576	274,290	6,546	775	12,354	8,000

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

	LINE ITEM		ALLOCATION FACTOR	
	PLANT IN SERVICE:			
375	Structures & Improvements	32,605	13	Distribution Mains
		4,720		Direct to Air Force Customer
376	Mains	6,282,000	9	Average Customers @ Distribution
		11,168,000	5	2-Day Peak @ Distribution
378	Meas. & Reg. Sta. Equip. - General	238,547	13	Distribution Mains
		5,432		Direct to Firm General Customer
379	Meas. & Reg. Sta. Equip. - City Gate	18,848		Direct to Air Force Customer
		4,920		Direct to Small Int. Customer
		34,855		Direct to Large Int. Customer
383	Service Regulators	799,331	10	Wtd Customers Excl. AF, LI & Firm Contract
		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.	55,583		Direct to Large Int. Customer
		7,846		Direct to Small Int. Customer
380	Services	5,231,490	10	Wtd Customers Excl. AF, LI & Firm Contract
381	Meters	5,801,088	10	Wtd Customers Excl. AF, LI & Firm Contract
		14,025		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	38,915	13	Distribution Mains
389	Total General Plant	9,132,624	15	Distribution Plant
389	Total Common Plant	2,223,008	15	Distribution Plant
386.3	Gas Plant Leased to Others	0	15	Distribution Plant
	ACCUMULATED RESERVE FOR DEPRECIATION REPORT:			
375	Structures & Improvements	9,972	17	Structures & Improvements
376	Mains	12,423,375	13	Distribution Mains
378	Meas. & Reg. Sta. Equip. - General	105,319	18	Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. Equip. - City Gate	36,275	19	Meas. & Reg. Eqpt.- City Gate
380	Services	4,925,118	10	Wtd Customers Excl. AF, LI & Firm Contract
381	Meters	2,150,241	10	Wtd Customers Excl. AF, LI & Firm Contract
383	Service Regulators	326,174	20	Service Regulators
385	Indust. Meas. & Reg. Sta. Equip.	20,104	21	Ind. Meas. & Reg. Sta. Eqpt.
386	Other Property on Customer's Premises	129,298	13	Distribution Mains
387	Cathodic Protection & Other Equipment	82,527	13	Distribution Mains
374	Land Rights	4,958	13	Distribution Mains
	Total General Plant	2,231,366	15	Distribution Plant
	Total Common Plant	945,105	15	Distribution Plant
386.3	Gas Plant Leased to Others	(91)	15	Distribution Plant
	CONSTRUCTION WORK IN PROGRESS REPORT:			
	CWIP in Service pending Classification	264,640	15	Distribution Plant

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

LINE ITEM		ALLOCATION FACTOR	
OPERATING REVENUE REPORT:			
Residential	4,264,435		Direct to Residential Demand
	9,782,481		Direct to Residential Energy
	2,939,720		Direct to Residential Customer
Firm General	2,935,557		Direct to Firm General Demand
	5,874,034		Direct to Firm General Energy
	541,425		Direct to Firm General Customer
Firm Contract	190,716		Direct to Firm Contract Demand
	2,456,526		Direct to Firm Contract Energy
	1,950		Direct to Firm Contract Customer
Air Force	243,631		Direct to Air Force Demand
	1,101,699		Direct to Air Force Energy
	1,140		Direct to Air Force Customer
Small Interruptible	59,593		Direct to Small Int. Demand
	324,504		Direct to Small Int. Energy
	41,873		Direct to Small Int. Customer
Large Interruptible	37,689		Direct to Large Int. Demand
	345,909		Direct to Large Int. Energy
	36,800		Direct to Large Int. Customer
Unbilled Revenue	167,597	26	Sales Revenue
Other Operating Revenue			
Reconnect Fees	8,966	11	Average Res. & Firm General Cust.
NSF Check Fees	10,720	11	Average Res. & Firm General Cust.
Work for Contractors, Municipalities & Others	20,086	24	Net Gas Plant in Service
Energy Diversion	48	24	Net Gas Plant in Service
CNG Compression & O&M Charges	0	24	Net Gas Plant in Service
Rent From Gas Property	84,274	24	Net Gas Plant in Service
Other Gas Revenues			
Miscellaneous Revenues	20,308	31	O&M Excl. Cost of Gas
Transport & Sales Penalty Revenue - Net	3,023	23	Sales & Transportation Rev.
OPERATION & MAINTENANCE EXPENSE REPORT:			
Cost of Purchased Gas	4,264,435		Direct to Residential Demand
	6,118,819		Direct to Residential Energy
	2,935,557		Direct to Firm General Demand
	4,152,251		Direct to Firm General Energy
	190,716		Direct to Firm Contract Demand
	2,039,905		Direct to Firm Contract Energy
	243,631		Direct to Air Force Demand
	1,083,599		Direct to Air Force Energy
	59,593		Direct to Small Int. Demand
	68,124		Direct to Small Int. Energy
	37,689		Direct to Large Int. Demand
	157,630		Direct to Large Int. Energy

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

	LINE ITEM		ALLOCATION FACTOR
813	Other Gas Supply Expenses	64,321	3 Dk Sales
870	Operation Supervision & Maintenance	391,213	27 All Other Dist. Operation Exp.
871	Load Dispatch	31,454	1 Dk Throughput
874	Mains & Services	722,091	22 Mains & Services
875	Measuring Stations - General	5,970	18 Meas. & Reg. Sta. Eqpt.- General
876	Measuring Stations - Industrial	5,896	21 Ind. Meas. & Reg. Sta. Eqpt.
877	Measuring Stations - City Gate	48	19 Meas. & Reg. Eqpt.- City Gate
878	Meters & House Regulators	240,930	16 Meters & Regulators
879	Customer Installations	435,155	10 Wtd Customers Excl. AF, LI & Firm Contract
880	Other Gas Distribution	529,606	27 All Other Dist. Operation Exp.
881	Rents	32,909	27 All Other Dist. Operation Exp.
885	Maintenance Supervision & Engineering	66,327	28 All Other Dist. Maintenance Exp.
886	Structures & Improvements	2,349	17 Structures & Improvements
887	Mains	55,967	13 Distribution Mains
889	Measuring Stations - General	6,203	18 Meas. & Reg. Sta. Eqpt.- General
890	Measuring Stations - Industrial	4,624	21 Ind. Meas. & Reg. Sta. Eqpt.
891	Measuring Stations - City Gate	0	19 Meas. & Reg. Eqpt.- City Gate
892	Services	29,333	12 Weighted Customers @ Distribution
893	Meters & House Regulators	42,708	16 Meters & Regulators
894	Other Equipment	72,107	28 All Other Dist. Maintenance Exp.
901	Customer Accounts	80,928	8 Average Customers
902	Meter Reading	263,402	10 Wtd Customers Excl. AF, LI & Firm Contract
903	Customer Records & Collection	724,755	8 Average Customers
904	Uncollectible Accounts	81,448	8 Average Customers
905	Miscellaneous Customer Accounts	92,671	8 Average Customers
907	Customer Service & Info.	63,686	8 Average Customers
911	Sales Expenses	252,371	8 Average Customers
920	Administration & General	1,964,267	30 O&M Excl. Gas Cost and A&G
	DEPRECIATION EXPENSE REPORT:		
376	Mains	718,378	13 Distribution Mains
375	Structures	896	17 Structures & Improvements
378	Meas. & Reg. Sta. - General	5,552	18 Meas. & Reg. Sta. Eqpt.- General
379	Meas. & Reg. Sta. - City Gate	1,606	19 Meas. & Reg. Eqpt.- City Gate
380	Services	419,675	10 Wtd Customers Excl. AF, LI & Firm Contract
381	Meters	145,918	10 Wtd Customers Excl. AF, LI & Firm Contract
383	Service Regulators	19,288	20 Service Regulators
385	Measuring & Reg. Equip. - Indust.	1,211	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	113,595	15 Distribution Plant
	Total Common Plant	157,347	15 Distribution Plant
386.3	Gas Plant Leased to Others	0	15 Distribution Plant

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

LINE ITEM		ALLOCATION FACTOR
TAXES OTHER THAN INCOME REPORT:		
Ad Valorem Taxes	387,047	15 Distribution Plant
Other Taxes - Payroll, Franchise, Other	332,949	31 O&M Excl. Cost of Gas
DEFERRED INCOME TAXES REPORT:		
Management Incentive Compensation	(11,356)	25 Total Gas Plant in Service
Pension Expense	119,533	25 Total Gas Plant in Service
Sundry Reserves	1,110	25 Total Gas Plant in Service
Reserve For Deferred Maintenance	1,036	25 Total Gas Plant in Service
Property Insurance Adjustment	(3,902)	25 Total Gas Plant in Service
Bad Debt Expense	17,663	23 Sales & Transportation Rev.
Accrued Vacation	9,310	31 O&M Excl. Cost of Gas
Capitalized Overheads	(63,089)	25 Total Gas Plant in Service
Customer Advances Total	335	11 Average Res. & Firm General Cust.
Restricted Stock Bonus Plan	9,450	31 O&M Excl. Cost of Gas
FAS 106 -OPRB	5,564	31 O&M Excl. Cost of Gas
Deferred Compensation - Directors	(2,897)	31 O&M Excl. Cost of Gas
Board of Directors - Retirement Benefits	(44,825)	31 O&M Excl. Cost of Gas
Demand Charges	4,470	2 2-Day Peak Sales
PCB Related Income	(1,295)	25 Total Gas Plant in Service
Liberalized Deprec. & Other Prop. Timing Differ.	(38,841)	25 Total Gas Plant in Service
Unrecovered Purchased Gas Costs	(292,849)	33 Total Gas Costs
Rate Case Expense	0	30 O&M Excl. Gas Cost and A&G
Amort. of Loss on Bond Retirements	(23,034)	24 Net Gas Plant in Service
FAS 106 Deferred Expense	(5,552)	31 O&M Excl. Cost of Gas
Gas IRP	0	3 Dk Sales
Closing/Filing and Out of Period & Fed/State FAS	211,943	25 Total Gas Plant in Service
Accumulated Balance 6/30/02	(1,821,350)	25 Total Gas Plant in Service
INCOME TAXES REPORT:		
Interest Charges	690,972	24 Net Gas Plant in Service
Deductions		
Management Incentive Compensation	(32,446)	25 Total Gas Plant in Service
Pension Expense	341,523	25 Total Gas Plant in Service
Sundry Reserves	3,171	25 Total Gas Plant in Service
Reserve For Deferred Maintenance	3,062	25 Total Gas Plant in Service
Property Insurance Adjustment	(11,149)	25 Total Gas Plant in Service
Bad Debt Expense	50,467	23 Sales & Transportation Rev.
Accrued Vacation	26,600	31 O&M Excl. Cost of Gas
Capitalized Overheads	(180,254)	25 Total Gas Plant in Service
Customer Advances	957	11 Average Res. & Firm General Cust.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

LINE ITEM		ALLOCATION FACTOR	
Restricted Stock Bonus Plan	27,001	31	O&M Excl. Cost of Gas
FAS 106 - OPRB	15,897	31	O&M Excl. Cost of Gas
Deferred Compensation - Directors	(8,278)	31	O&M Excl. Cost of Gas
Board of Directors - Retirement Benefits	(128,072)	31	O&M Excl. Cost of Gas
Demand Charges	12,771	2	2-Day Peak Sales
PCB Related Income	(9,863)	25	Total Gas Plant in Service
Plant Reclassification	17,187	25	Total Gas Plant in Service
Liberalized Depreciation & OPTD	(499,963)	25	Total Gas Plant in Service
Contributions in Aid of Construction	(705)	25	Total Gas Plant in Service
Purchased Gas Cost Adjustment	(836,712)	33	Total Gas Costs
Rate Case Expense	0	30	O&M Excl. Gas Cost and A&G
Amort. of Loss on Bond Retirements	(65,811)	24	Net Gas Plant in Service
FAS 106 - Deferred Expense	(15,863)	31	O&M Excl. Cost of Gas
Gas IRP	0	24	Net Gas Plant in Service
Disallowed Meals & Entertainment	(14,214)	31	O&M Excl. Cost of Gas
Federal Non-Hwy. Use Tax Credit	(2,701)	25	Total Gas Plant in Service
Preferred Dividend Paid Deduction	8,064	25	Total Gas Plant in Service
State Income Tax	0	35	Taxable Income
Rounding & Prior Year Adjustments	0	25	Total Gas Plant in Service
Taxable Income @ Federal Tax Rate	35.00%		Direct Input
Credits & Adjustments	(210,207)	40	Total Tax Deductions & Adjustments
WORKING CAPITAL REPORT:			
Materials & Supplies	299,635	15	Distribution Plant
Prepaid Insurance	55,991	25	Total Gas Plant in Service
Unamortized FAS 106 Costs - Other	166,563	31	O&M Excl. Cost of Gas
RATE BASE REPORT:			
Investment Tax Credit Balance	(33,248)	25	Total Gas Plant in Service
Customer Advances for Const.	(35,298)	11	Average Res. & Firm General Cust.
	(16,199)		Direct to Firm General
	(10,881)		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	10.303%		
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%		

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

LINE ITEM			ALLOCATION FACTOR
Billing Units @ Customer			
Dk Throughput (Projected 2003)	3,151,151		Direct to Residential Energy
	2,151,036		Direct to Firm General Energy
	625,741		Direct to Firm Contract Energy
	569,719		Direct to Air Force Energy
	403,210		Direct to Small Int. Energy
	747,790		Direct to Large Int. Energy
Bills (Average Customers * 12)	430,092		Direct to Residential Customer
	58,560		Direct to Firm General Customer
	12		Direct to Firm Contract Customer
	12		Direct to Air Force Customer
	504		Direct to Small Int. Customer
	132		Direct to Large Int. Customer
ADJUSTMENTS TO OPERATING INCOME:			
Revenue:			
Projected 2003 @ Current Rates			
Residential	190,190		Direct to Residential Demand
	3,310,790		Direct to Residential Energy
	72,436		Direct to Residential Customer
Firm General	105,253		Direct to Firm General Demand
	2,147,715		Direct to Firm General Energy
	17,025		Direct to Firm General Customer
Firm Contract	1,294		Direct to Firm Contract Demand
	(209,147)		Direct to Firm Contract Energy
	(150)		Direct to Firm Contract Customer
Air Force	(16,313)		Direct to Air Force Demand
	422,869		Direct to Air Force Energy
	0		Direct to Air Force Customer
Small Interruptible	(4,800)		Direct to Small Int Demand
	(24,424)		Direct to Small Int Energy
	(2,253)		Direct to Small Int Customer
Large Interruptible	(2,352)		Direct to Large Int Demand
	4,379		Direct to Large Int Energy
	(5,600)		Direct to Large Int Customer
Unbilled Revenues	(167,597)	26	Sales Revenue
Cost of Gas			
Current Cost of Purchased Gas	190,190		Direct to Residential Demand
	2,855,659		Direct to Residential Energy
	105,253		Direct to Firm General Demand
	1,973,900		Direct to Firm General Energy
	1,294		Direct to Firm Contract Demand

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
ALLOCATION ASSIGNMENT REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

LINE ITEM	ALLOCATION FACTOR		
	(16,259)		Direct to Firm Contract Energy
	(16,313)		Direct to Air Force Demand
	405,646		Direct to Air Force Energy
	(4,800)		Direct to Small Int Demand
	42,264		Direct to Small Int Energy
	(2,352)		Direct to Large Int Demand
	59,646		Direct to Large Int Energy
Other O&M Expense			
Labor Expense			
Other Gas Supply	7,232	30	O&M Excl. Cost of Gas and A&G
Distribution	235,809	39	Distribution O&M
Customer Accounts	104,957	38	Customer Expense Accounts O&M
Customer Service & Information	4,867	8	Average Customers
Sales	24,337	8	Average Customers
Administrative & General	84,988	30	O&M Excl. Cost of Gas and A&G
Benefits Expense	403,447	30	O&M Excl. Cost of Gas and A&G
Insurance Expense	54,700	30	O&M Excl. Cost of Gas and A&G
Advertising Expense	(22,097)	8	Average Customers
Postage Expense	9,511	8	Average Customers
Industry Dues	1,894	30	O&M Excl. Cost of Gas and A&G
Rate Case Expense	17,839	30	O&M Excl. Cost of Gas and A&G
All Other O&M	102,586	31	O&M Excl Cost of Gas
Depreciation Expense	229,954	15	Distribution Plant
Taxes Other Than Income			
Ad Valorem Taxes	21,597	15	Distribution Plant
Other Taxes - Payroll, Franchise, Other	33,474	31	O&M Excl Cost of Gas
Current Income Taxes			
Interest Expense	26,651	24	Net Gas Plant in Service
Other Tax Deductions			
Management Incentive Compensation	32,446	25	Total Gas Plant in Service
Pension Expense	(237,623)	25	Total Gas Plant in Service
Sundry Reserves	(3,171)	25	Total Gas Plant in Service
Reserve for Deferred Maintenance	(3,062)	25	Total Gas Plant in Service
Property Insurance Adjustment	11,149	25	Total Gas Plant in Service
Bad Debt Expense	(50,467)	23	Sales & Transportation Rev.
Accrued Vacation	(26,600)	31	O&M Excl. Cost of Gas
Capitalized Overheads	180,254	25	Total Gas Plant in Service
Customer Advances	(957)	11	Average Res. & Firm General Cust.
Restricted Stock Bonus Plan	(27,001)	31	O&M Excl. Cost of Gas
FAS 106 - OPRB	(98,787)	31	O&M Excl Cost of Gas
Deferred Compensation	8,278	31	O&M Excl Cost of Gas
BOD Retirement	128,072	31	O&M Excl Cost of Gas
Demand Charges	(12,771)	2	2-Day Peak Sales
PCB Related Income	9,863	25	Total Gas Plant in Service

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LINE ITEM		ALLOCATION FACTOR	
Plant Reclassification	(17,187)	25	Total Gas Plant in Service
Liberalized Depreciation & Other	(220,262)	25	Total Gas Plant in Service
Contributions in Aid of Construction	705	25	Total Gas Plant in Service
Purchased Gas Cost Adjustment	3,186,105	33	Total Gas Costs
Amortization of Loss on Bond Retirements	(16,763)	24	Net Gas Plant in Service
FAS 106 Deferred Expense	(1)	31	O&M Excl Cost of Gas
Meals & Entertainment	(6,559)	31	O&M Excl Cost of Gas
Federal Nonhwy Use Tax Credit	2,701	25	Total Gas Plant in Service
Deferred Income Taxes			
Management Incentive Compensation	11,356	25	Total Gas Plant in Service
Pension Expense	(146,633)	25	Total Gas Plant in Service
Sundry Reserves	(1,110)	25	Total Gas Plant in Service
Reserve for Deferred Maintenance	(1,036)	25	Total Gas Plant in Service
Property Insurance Adjustment	3,902	25	Total Gas Plant in Service
Bad Debt Expense	(17,663)	23	Sales & Transportation Rev.
Accrued Vacation	(9,310)	31	O&M Excl. Cost of Gas
Capitalized Overheads	63,089	25	Total Gas Plant in Service
Customer Advances	(335)	11	Average Res. & Firm General Cust.
Restricted Stock Bonus Plan	(9,450)	31	O&M Excl. Cost of Gas
FAS 106	(5,564)	31	O&M Excl. Cost of Gas
Deferred Compensation	2,897	31	O&M Excl. Cost of Gas
BOD Retirement	44,825	31	O&M Excl. Cost of Gas
Demand Charges	(4,470)	2	2-Day Peak Sales
PCB Related Income	1,295	25	Total Gas Plant in Service
Liberalized Deprec & Other Prop Timing Diff	(76,530)	25	Total Gas Plant in Service
Unrecovered Purchased Gas Cost	1,115,137	33	Total Gas Costs
Amort of Loss on Bond Retirements	23,034	24	Net Gas Plant in Service
FAS 106 Deferred Expense	5,552	31	O&M Excl. Cost of Gas
Closing/Filing and Out of Period	(211,943)	25	Total Gas Plant in Service
ADJUSTMENTS TO RATE BASE:			
Plant in Service			
Distribution Plant	1,788,388	15	Distribution Plant
General Plant	60,525	15	Distribution Plant
Common Plant	443,816	15	Distribution Plant
Accumulated Reserve			
Distribution Plant	1,294,589	15	Distribution Plant
General Plant	(117,538)	15	Distribution Plant
Common Plant	64,991	15	Distribution Plant
CWIP in Service Pending Reclassification	(264,640)	15	Distribution Plant

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LINE ITEM		ALLOCATION FACTOR	
Additions to Rate Base:			
Materials & Supplies	(46,104)	15	Distributin Plant
Prepayments	(870)	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	(154,288)	25	Total Gas Plant in Service
Accumulated Investment Tax Credits	(14,924)	25	Total Gas Plant in Service
Customer Advances	(15,124)	11	Average Res & Firm Gneral Customers

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		Total	Residential			Firm General		
		South Dakota	Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput	7,648,647		3,151,151			2,151,036	
		100.000000%	0.000000%	41.198802%	0.000000%	0.000000%	28.123092%	0.000000%
2.	2-Day Peak Sales	100,601	57,340			36,832		
		100.000000%	56.997446%	0.000000%	0.000000%	36.611962%	0.000000%	0.000000%
3.	Dk Sales	6,619,527		3,151,151			2,151,036	
		100.000000%	0.000000%	47.603870%	0.000000%	0.000000%	32.495313%	0.000000%
4.	Dk Throughput @ Distribution	6,428,415		3,003,356			1,958,358	
		100.000000%	0.000000%	46.720007%	0.000000%	0.000000%	30.464088%	0.000000%
5.	2-Day Peak @ Distribution	96,581	56,642			35,921		
		100.000000%	58.647146%	0.000000%	0.000000%	37.192616%	0.000000%	0.000000%
8.	Average Customers	40,776			35,841			4,880
		100.000000%	0.000000%	0.000000%	87.897293%	0.000000%	0.000000%	11.967824%
9.	Average Customers @ Distribution	38,944			34,268			4,629
		100.000000%	0.000000%	0.000000%	87.993016%	0.000000%	0.000000%	11.886298%
10.	Weighted Customers Excl. AF, LI & Firm Contra	56,705			35,841			19,520
		100.000000%	0.000000%	0.000000%	63.206067%	0.000000%	0.000000%	34.423772%
11.	Average Res. & Firm General Cust.	40,722			35,841			4,880
		100.000000%	0.000000%	0.000000%	88.013850%	0.000000%	0.000000%	11.983694%
12.	Weighted Customers @ Distribution	55,088			34,268			18,516
		100.000000%	0.000000%	0.000000%	62.205925%	0.000000%	0.000000%	33.611676%
13	Distribution Mains	17,449,998	6,549,713	0	5,527,721	4,153,671	0	746,697
		100.000000%	37.534175%	0.000000%	31.677488%	23.803275%	0.000000%	4.279066%

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		Firm Contract			Air Force		
		Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput		625,741			569,719	
		0.000000%	8.181068%	0.000000%	0.000000%	7.448625%	0.000000%
2.	2-Day Peak Sales	1,714			1,561		
		1.703760%	0.000000%	0.000000%	1.551674%	0.000000%	0.000000%
3.	Dk Sales		625,741			569,719	
		0.000000%	9.452956%	0.000000%	0.000000%	8.606642%	0.000000%
4.	Dk Throughput @ Distribution		625,741			0	
		0.000000%	9.733986%	0.000000%	0.000000%	0.000000%	0.000000%
5.	2-Day Peak @ Distribution	1,714			0		
		1.774676%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
8.	Average Customers			1			1
		0.000000%	0.000000%	0.002452%	0.000000%	0.000000%	0.002452%
9.	Average Customers @ Distribution			1			0
		0.000000%	0.000000%	0.002568%	0.000000%	0.000000%	0.000000%
10.	Weighted Customers Excl. AF, LI & Firm Contra						0
		0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11.	Average Res. & Firm General Cust.			1			
		0.000000%	0.000000%	0.002456%	0.000000%	0.000000%	0.000000%
12.	Weighted Customers @ Distribution			112			0
		0.000000%	0.000000%	0.203311%	0.000000%	0.000000%	0.000000%
13	Distribution Mains	198,196	0	161	0	0	0
		1.135794%	0.000000%	0.000923%	0.000000%	0.000000%	0.000000%

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		Small Interruptible			Large Interruptible		
		Demand	Energy	Customer	Demand	Energy	Customer
1.	Dk Throughput		403,210			747,790	
		0.000000%	5.271651%	0.000000%	0.000000%	9.776762%	0.000000%
2.	2-Day Peak Sales	1,105			2,049		
		1.098399%	0.000000%	0.000000%	2.036759%	0.000000%	0.000000%
3.	Dk Sales		38,760			83,120	
		0.000000%	0.585540%	0.000000%	0.000000%	1.255679%	0.000000%
4.	Dk Throughput @ Distribution		329,290			511,670	
		0.000000%	5.122414%	0.000000%	0.000000%	7.959505%	0.000000%
5.	2-Day Peak @ Distribution	902			1,402		
		0.933931%	0.000000%	0.000000%	1.451631%	0.000000%	0.000000%
8.	Average Customers			42			11
		0.000000%	0.000000%	0.103002%	0.000000%	0.000000%	0.026977%
9.	Average Customers @ Distribution			37			9
		0.000000%	0.000000%	0.095008%	0.000000%	0.000000%	0.023110%
10.	Weighted Customers Excl. AF, LI & Firm Contra			1,344			0
		0.000000%	0.000000%	2.370161%	0.000000%	0.000000%	0.000000%
11.	Average Res. & Firm General Cust.						
		0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12.	Weighted Customers @ Distribution			1,184			1,008
		0.000000%	0.000000%	2.149288%	0.000000%	0.000000%	1.829800%
13	Distribution Mains	104,301	0	5,968	162,118	0	1,452
		0.597714%	0.000000%	0.034201%	0.929043%	0.000000%	0.008321%

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		Total	Residential			Firm General		
		South Dakota	Demand	Energy	Customer	Demand	Energy	Customer
15.	Distribution Plant	30,084,449	6,786,366	0	13,205,932	4,303,750	0	4,857,048
		100.000000%	22.557720%	0.000000%	43.896207%	14.305564%	0.000000%	16.144713%
16.	Meters & Regulators	6,637,173	0	0	4,171,866	0	0	2,277,064
		100.000000%	0.000000%	0.000000%	62.856069%	0.000000%	0.000000%	34.307739%
17.	Structures & Improvements	37,324	12,238	0	10,328	7,761	0	1,395
		100.000000%	32.788553%	0.000000%	27.671204%	20.793591%	0.000000%	3.737542%
18.	Meas. & Reg. Sta. Eqpt.- General	243,980	89,537	0	75,566	56,782	0	15,640
		100.000000%	36.698500%	0.000000%	30.972211%	23.273219%	0.000000%	6.410362%
19.	Meas. & Reg. Eqpt.- City Gate	58,623	0	0	0	0	0	0
		100.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
20.	Service Regulators	822,060	0	0	505,226	0	0	280,111
		100.000000%	0.000000%	0.000000%	61.458531%	0.000000%	0.000000%	34.074277%
21.	Ind. Meas. & Reg. Sta. Eqpt.	63,429	0	0	0	0	0	0
		100.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
22.	Mains & Services	22,681,327	6,549,713	0	8,834,340	4,153,671	0	2,547,573
		100.000000%	28.877115%	0.000000%	38.949837%	18.313175%	0.000000%	11.232028%
23.	Sales & Transportation Rev.	31,347,278	4,287,357	9,835,064	2,955,522	2,951,336	5,905,608	544,335
		100.000000%	13.676966%	31.374539%	9.428321%	9.414967%	18.839301%	1.736467%
24.	Net Gas Plant in Service	18,050,347	3,845,121	0	8,084,333	2,438,482	0	3,082,815
		100.000000%	21.302200%	0.000000%	44.787687%	13.509336%	0.000000%	17.078979%
25.	Total Gas Plant in Service	41,440,084	9,347,938	0	18,190,624	5,928,237	0	6,690,382
		100.000000%	22.557720%	0.000000%	43.896204%	14.305562%	0.000000%	16.144711%

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		Firm Contract			Air Force		
		Demand	Energy	Customer	Demand	Energy	Customer
15.	Distribution Plant	205,356 0.682599%	0 0.000000%	14,191 0.047171%	0 0.000000%	0 0.000000%	26,655 0.088601%
16.	Meters & Regulators	0 0.000000%	0 0.000000%	14,025 0.211310%	0 0.000000%	0 0.000000%	0 0.000000%
17.	Structures & Improvements	370 0.991319%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	4,720 12.646019%
18.	Meas. & Reg. Sta. Eqpt.- General	2,709 1.110337%	0 0.000000%	2 0.000820%	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%	18,848 32.151204%
20.	Service Regulators	0 0.000000%	0 0.000000%	0 0.000000%	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	198,196 0.873829%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%
23.	Sales & Transportation Rev.	191,741 0.611667%	2,469,730 7.878611%	1,960 0.006253%	244,941 0.781379%	1,107,621 3.533388%	1,146 0.003656%
24.	Net Gas Plant in Service	116,354 0.644608%	0 0.000000%	17,931 0.099339%	0 0.000000%	0 0.000000%	20,979 0.116225%
25.	Total Gas Plant in Service	282,869 0.682598%	0 0.000000%	19,548 0.047172%	0 0.000000%	0 0.000000%	36,717 0.088603%

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		Small Interruptible			Large Interruptible		
		Demand	Energy	Customer	Demand	Energy	Customer
15.	Distribution Plant	108,071 0.359225%	0 0.000000%	308,037 1.023908%	167,976 0.558348%	0 0.000000%	101,067 0.335944%
16.	Meters & Regulators	0 0.000000%	0 0.000000%	165,093 2.487399%	0 0.000000%	0 0.000000%	9,125 0.137483%
17.	Structures & Improvements	195 0.522452%	0 0.000000%	11 0.029472%	303 0.811810%	0 0.000000%	3 0.008038%
18.	Meas. & Reg. Sta. Eqpt.- General	1,426 0.584474%	0 0.000000%	82 0.033609%	2,216 0.908271%	0 0.000000%	20 0.008197%
19.	Meas. & Reg. Eqpt.- City Gate	0 0.000000%	0 0.000000%	4,920 8.392610%	0 0.000000%	0 0.000000%	34,855 59.456186%
20.	Service Regulators	0 0.000000%	0 0.000000%	27,598 3.357176%	0 0.000000%	0 0.000000%	9,125 1.110016%
21.	Ind. Meas. & Reg. Sta. Eqpt.	0 0.000000%	0 0.000000%	7,846 12.369736%	0 0.000000%	0 0.000000%	55,583 87.630264%
22.	Mains & Services	104,301 0.459854%	0 0.000000%	129,963 0.572996%	162,118 0.714764%	0 0.000000%	1,452 0.006402%
23.	Sales & Transportation Rev.	59,913 0.191127%	326,248 1.040754%	42,098 0.134296%	37,892 0.120878%	347,768 1.109404%	36,998 0.118026%
24.	Net Gas Plant in Service	61,233 0.339234%	0 0.000000%	203,247 1.126001%	95,175 0.527275%	0 0.000000%	84,677 0.469116%
25.	Total Gas Plant in Service	148,864 0.359227%	0 0.000000%	424,309 1.023910%	231,380 0.558348%	0 0.000000%	139,216 0.335945%

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		Total	Residential			Firm General		
		South Dakota	Demand	Energy	Customer	Demand	Energy	Customer
26.	Sales Revenue	31,179,682	4,264,435	9,782,481	2,939,720	2,935,557	5,874,034	541,425
		100.000000%	13.676967%	31.374537%	9.428319%	9.414968%	18.839301%	1.736467%
27.	All Other Dist. Operation Exp.	1,410,089	210,710	0	709,585	133,627	0	313,943
		100.000000%	14.943028%	0.000000%	50.322001%	9.476494%	0.000000%	22.264056%
28.	All Other Dist. Maintenance Exp.	138,837	23,283	0	64,742	14,766	0	27,304
		100.000000%	16.770025%	0.000000%	46.631662%	10.635493%	0.000000%	19.666227%
30.	O&M Excl. Gas Cost and A&G	4,298,471	400,494	43,578	2,624,976	253,984	29,747	826,658
		100.000000%	9.317128%	1.013802%	61.067668%	5.908706%	0.692037%	19.231443%
31.	O&M Excl. Cost of Gas	6,262,737	583,507	63,492	3,824,508	370,047	43,340	1,204,415
		100.000000%	9.317123%	1.013806%	61.067677%	5.908711%	0.692030%	19.231448%
33.	Total Cost of Gas	21,351,949	4,264,435	6,118,819	0	2,935,557	4,152,251	0
		100.000000%	19.972111%	28.656958%	0.000000%	13.748426%	19.446707%	0.000000%
35.	Taxable Income	2,160,766	(885,610)	3,875,456	(1,957,482)	(551,742)	1,862,299	(1,069,969)
		100.000000%	-40.985928%	179.355654%	-90.592040%	-25.534556%	86.186982%	-49.518041%
38.	Customer Account Expense O&M	80,928	0	0	71,134	0	0	9,685
		100.000000%	0.000000%	0.000000%	87.897885%	0.000000%	0.000000%	11.967428%
39.	Distribution O&M	2,674,888	400,494	12,959	1,319,465	253,984	8,846	580,899
		100.000000%	14.972364%	0.484469%	49.327860%	9.495127%	0.330705%	21.716760%
40.	Total Tax Deductions & Adjustments	(1,299,335)	(258,104)	(224,924)	(242,882)	(172,308)	(153,875)	(87,668)
		100.000000%	19.864314%	17.310701%	18.692793%	13.261245%	11.842596%	6.747144%

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		Firm Contract			Air Force		
		Demand	Energy	Customer	Demand	Energy	Customer
26.	Sales Revenue	190,716 0.611668%	2,456,526 7.878611%	1,950 0.006254%	243,631 0.781377%	1,101,699 3.533388%	1,140 0.003656%
27.	All Other Dist. Operation Exp.	6,376 0.452170%	0 0.000000%	509 0.036097%	0 0.000000%	0 0.000000%	15 0.001064%
28.	All Other Dist. Maintenance Exp.	705 0.507790%	0 0.000000%	151 0.108761%	0 0.000000%	0 0.000000%	0 0.000000%
30.	O&M Excl. Gas Cost and A&G	12,120 0.281961%	8,653 0.201304%	1,186 0.027591%	0 0.000000%	7,879 0.183298%	354 0.008235%
31.	O&M Excl. Cost of Gas	17,658 0.281953%	12,607 0.201302%	1,728 0.027592%	0 0.000000%	11,479 0.183290%	516 0.008239%
33.	Total Cost of Gas	190,716 0.893202%	2,039,905 9.553718%	0 0.000000%	243,631 1.141025%	1,083,599 5.074942%	0 0.000000%
35.	Taxable Income	(24,147) -1.117520%	492,984 22.815242%	(493) -0.022816%	10,289 0.476174%	52,935 2.449826%	(883) -0.040865%
38.	Customer Account Expense O&M	0 0.000000%	0 0.000000%	2 0.002471%	0 0.000000%	0 0.000000%	2 0.002471%
39.	Distribution O&M	12,120 0.453103%	2,573 0.096191%	1,154 0.043142%	0 0.000000%	2,343 0.087592%	322 0.012038%
40.	Total Tax Deductions & Adjustments	(10,128) 0.779476%	(76,157) 5.861229%	(261) 0.020087%	(8,955) 0.689199%	(40,858) 3.144532%	(406) 0.031247%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

		Small Interruptible			Large Interruptible		
		Demand	Energy	Customer	Demand	Energy	Customer
26.	Sales Revenue	59,593	324,504	41,873	37,689	345,909	36,800
		0.191128%	1.040755%	0.134296%	0.120877%	1.109405%	0.118026%
27.	All Other Dist. Operation Exp.	3,356	0	21,180	5,215	0	5,573
		0.237999%	0.000000%	1.502033%	0.369835%	0.000000%	0.395223%
28.	All Other Dist. Maintenance Exp.	371	0	2,285	576	0	4,654
		0.267220%	0.000000%	1.645815%	0.414875%	0.000000%	3.352132%
30.	O&M Excl. Gas Cost and A&G	6,378	2,035	47,648	9,912	3,883	18,986
		0.148378%	0.047342%	1.108487%	0.230594%	0.090334%	0.441692%
31.	O&M Excl. Cost of Gas	9,293	2,965	69,422	14,441	5,657	27,662
		0.148386%	0.047344%	1.108493%	0.230586%	0.090328%	0.441692%
33.	Total Cost of Gas	59,593	68,124	0	37,689	157,630	0
		0.279099%	0.319053%	0.000000%	0.176513%	0.738246%	0.000000%
35.	Taxable Income	(14,485)	257,233	(53,244)	(24,918)	189,937	2,606
		-0.670364%	11.904713%	-2.464126%	-1.153202%	8.790262%	0.120605%
38.	Customer Account Expense O&M	0	0	83	0	0	22
		0.000000%	0.000000%	0.102560%	0.000000%	0.000000%	0.027185%
39.	Distribution O&M	6,378	1,658	40,070	9,912	3,075	18,636
		0.238440%	0.061984%	1.498007%	0.370558%	0.114958%	0.696702%
40.	Total Tax Deductions & Adjustments	(3,775)	(2,191)	(5,477)	(3,759)	(5,705)	(1,902)
		0.290533%	0.168625%	0.421523%	0.289302%	0.439071%	0.146383%

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - SOUTH DAKOTA

Customer Class/Rate	Projected 2003 Customers 1/	Projected 2003 Dk	Projected 2003 Revenue 2/	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	35,841	3,151,151	$20,560,052	$21,761,669	$1,201,617	5.8%
Firm General Service - Rate 70 & 72	4,880	2,151,036	11,621,009	12,592,360	971,351	8.4%
Firm Contract Service Rate	1	625,741	2,441,189	2,441,189	0	0.0%
Air Force Service - Rate 64	1	569,719	1,753,026	1,753,176	150	0.0%
Small Interruptible						
Sales - Rate 71	12	38,760	188,950			
Transport - Rate 81	33	364,450	205,543			
Total Small Interruptible	45	403,210	394,493	394,675	182	0.0%
Large Interruptible						
Sales - Rate 85	1	83,120	269,779			
Transport - Rate 82	13	664,670	147,046			
	14	747,790	416,825	416,905	80	0.0%
Total South Dakota	40,782	7,648,647	$37,186,594	$39,359,974	$2,173,380	5.8%

1/ Bills divided by 12.
2/ Rates effective as of December 1, 2002.

DOCKET NO. ____
RULE 20:10:13:98
STATEMENT O
PAGE 1 OF 1

MONTANA-DAKOTA UTILITIES CO.
PGA TARIFF SHEET
BLACK HILLS
EFFECTIVE DECEMBER 2002

	Residential & General Service	Large Interruptible	Air Force
Gas Cost Adjustment:			
Prior Cumulative Gas Cost Adjustment	($0.550)	($0.234)	$0.024
Current Gas Cost Adjustment (Exhibit B)	$1.123	$1.197	$1.184
Cumulative Gas Cost Adjustment	$0.573	$0.963	$1.208
Surcharge Adjustment:			
Current Adjustment	($0.630)	($0.490)	($0.495)
TOTAL PGA	**($0.057)**	**$0.473**	**$0.713**
TOTAL PGA - Current	($1.180)	($0.724)	($0.471)
Net Increase (Decrease)	**$1.123**	**$1.197**	**$1.184**

Gas Cost Level in Base Rates	$3.700	$2.084	$1.805
Plus: Total PGA	(0.057)	0.473	0.713
Total Gas Cost Level in Rates	$3.643	$2.557	$2.518

MONTANA-DAKOTA UTILITIES CO.
DESCRIPTION OF UTILITY OPERATIONS

Montana-Dakota Utilities Co. (Montana-Dakota), 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 June 30, 2002, the Company supplied natural gas at retail to approximately 212,960 customers located in 141 communities and adjacent rural areas. As of the same date, Montana-Dakota supplied electricity to approximately 116,660 customers located in 177 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 and clay products manufacturing. There has been a significant increase in oil and natural gas exploration and the value-added agricultural products industry in the Company's service territory. Energy services to major health-care facilities also rank high on the company's slate of non-residential customers.

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 June 30, 1994 with the South Dakota Public Utilities Commission in Docket No. NG94-012. The application requested an annual increase in revenues of $1,110,539, or an overall increase of 3.70%. The Commission issued an Order dated December 16, 1994 authorizing an increase of $500,000, or a 1.70% increase effective December 7, 1994. On December 30, 1994 the Commission issued an order authorizing an increase of $254,000 or 0.9% to reflect FAS 106. Rates were effective for service rendered on and after January 1, 1995.

MONTANA-DAKOTA UTILITIES CO.
INTERCOMPANY TRANSACTIONS
TOTAL COMPANY
FOR THE TWELVE MONTHS ENDING JUNE 30, 2002

Please see Rule 20:10:13:84, Statement H, Schedule H-4.

South Dakota Public Utilities Commission

WEEKLY FILINGS

For the Period of December 26, 2002 through January 1, 2003

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: 605-773-3705

CONSUMER COMPLAINTS

CT02-047 In the Matter of the Complaint filed by Patricia Bue on behalf of Stockholm Refrigeration, Inc., Stockholm, South Dakota, against QuantumLink Communications Regarding Unauthorized Switching of Services.

Complainant's representative states that Complainant's 800# was switched to QuantumLink without authorization. Complainant's representative requests $1,000.00 for the unauthorized switch as allowed by South Dakota law.

Staff Analyst: Amy Kayser
Staff Attorney: Kelly Frazier
Date Docketed: 12/30/02
Intervention Deadline: N/A

ELECTRIC

EL02-027 In the Matter of the Filing by MidAmerican Energy Company for Approval of Tariff Revisions.

Application by MidAmerican Energy Company to revise its disconnect notice including a version of the notice that displays a message regarding the amount of non-utility charges on the account. The company states this language is being added to reduce customer misunderstanding over utility and non-utility charges as they relate to disconnection.

Staff Analyst: Dave Jacobson
Staff Attorney: Karen Cremer
Date Docketed: 12/31/02
Intervention Deadline: 01/15/03

NATURAL GAS

NG02-011 - In the Matter of the Application of 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 $2,173,380, or 5.8% based on a 2003 projected test year. The proposed increase for a residential customer would average about $2.50 per month. The proposed rates may potentially affect about 40,800 natural gas customers in the Black Hills area of South Dakota.

Staff Analyst: Dave Jacobson
Staff Attorney: Karen Cremer
Date Docketed: 12/30/02
Intervention Deadline: 02/07/03

NG02-012 In the Matter of the Filing by MidAmerican Energy Company for Approval of Tariff Revisions.

Application by MidAmerican Energy Company to revise its disconnect notice including a version of the notice that displays a message regarding the amount of non-utility charges on the account. The company states this language is being added to reduce customer misunderstanding over utility and non-utility charges as they relate to disconnection.

Staff Analyst: Dave Jacobson
Staff Attorney: Karen Cremer
Date Docketed: 12/31/02
Intervention Deadline: 01/15/03

TELECOMMUNICATIONS

TC02-209 In the Matter of the Filing for Approval of an Amendment to an Interconnection Agreement between Qwest Corporation and Sprint Communications Company L.P.

On December 27, 2002, the Commission received a filing of a CLEC-To-CLEC Connections, CLEC-To-CLEC Cross Connections and Early Access Amendment to the Interconnection Agreement between Qwest Corporation and Sprint Communications Company L.P. According to the parties, this is an Amendment to the negotiated

Interconnection Agreement approved by the Commission in Docket TC01-151, effective November 13, 2001. According to the parties, the Agreement is amended by adding terms and conditions for CLEC-To-CLEC Connections, CLEC-To-CLEC Cross Connections and Early Access as set forth in Attachment 1 and Exhibit A, attached to the Amendment. 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 January 16, 2003. 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: Kelly Frazier
Date Docketed: 12/27/02
Initial Comments Due: 01/16/03

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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 NG02-011**

On December 30, 2002, 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 $2,173,380 or approximately 5.8%.

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 January 16, 2003, 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 February 7, 2003, 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 January 30, 2003. 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 January 30, 2003, pursuant to SDCL 49-34A-14; and it is further

ORDERED, that the deadline for filing petitions to intervene in this case is February 7, 2003.

Dated at Pierre, South Dakota, this 28th day of January, 2003.

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: 1/28/03

(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

CONTRACT BETWEEN
CHESAPEAKE REGULATORY CONSULTANTS, INC.
AND
THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

This Contract is entered into this 6th day of February, **2003**, 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. <u>Scope of Services</u>: Contractor agrees to provide consulting services to the Staff of the Commission in the following Commission Docket: NG02-011, 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 January 17, 2003, to Commission Staff. Contractor agrees to coordinate their filing 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-nine thousand eight hundred dollars and no cents ($49,800.00)**. 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 January 17, 2003, 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 financial report shall be submitted by the Contractor which shall include the nature of the work performed, the hours worked by and 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 voucher.

The Contractor may receive progress payments not 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, Special Assistant Attorney General — 2/6/03 DATE

COMMISSION:

ROBERT K. SAHR
Chairman

GARY HANSON
Commissioner

JAMES A. BURG
Commissioner

CONTRACTOR:

By:

Robert G. Towers — 2/3/03 DATE

its President
(Title)

Exhibit A

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

FEE SCHEDULE

		Hourly Rate
Robert G. Towers	Senior Consultant	$ 135.00
Basil L. Copeland, Jr.	Senior Economist	$ 130.00
David E. Peterson	Senior Consultant	$ 120.00

January 1, 2003

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

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

February 24, 2003

Ms. Heather K. Forney
Deputy Executive Director
South Dakota Public Utilities Commission
State Capitol Building
500 East Capitol
Pierre, SD 57501-5070

Re: Docket No. NG02-011 Filing Fee

Dear Ms. Forney:

Enclosed is a check in the amount of $15,000.00 in payment of filing fees associated with the above-referenced Docket No. NG02-011 rate case.

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 by Steve Reed

Donald R. Ball
Assistant Vice President -
Regulatory Affairs

RECEIVED
FEB 27 2003
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

THE FACE OF THIS DOCUMENT HAS A COLORED BACKGROUND ON WHITE PAPER

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

02/24/03

No. 971342

FIRST INTERSTATE BANK OF COMMERCE
BILLINGS, MONTANA

93-168
929

$**15,000.00**

FIFTEEN THOUSAND AND 00/100 ********

PAY TO THE ORDER OF

SD PUBLIC UTILITIES
COMMISSION
500 E CAPITOL
PIERRE SD 57501

General Fund

Martin A. White

⑈0097134 2⑈ ⑆092901683⑆ 00493⑈

VOID

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 NG02-011**

On December 30, 2002, 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 $2,173,380 or approximately 5.8%.

At its regularly scheduled meeting of January 16, 2003, 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 February 7, 2003. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by MDU for 90 days beyond January 30, 2003. 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**
April 23, 2003	Staff Prefiled Testimony Due
May 2, 2003	MDU Rebuttal Testimony Due
May 7 and 8, 2003	Hearing
May 27, 2003	Initial Briefs Due
June 6, 2003	Rebuttal Briefs Due

A hearing shall be held at 9:00 a.m., on Wednesday, May 7, 2003, and Thursday, May 8, 2003, 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 $2,173.380.

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 Wednesday, May 7, 2003, in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota, and if necessary, shall continue through Thursday, May 8, 2003.

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 20th day of March, 2003.

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: 3/20/03

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

ROBERT K. SAHR, Chairman

GARY HANSON, Commissioner

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 EXTENDING SUSPENSION OF IMPOSITION OF TARIFF NG02-011**

On December 30, 2002, 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 $2,173,380 or approximately 5.8%. On January 16, 2003, the Commission suspended the proposed schedule of rates for 90 days beyond January 30, 2003. On April 1, 2003, Commission Staff recommended that the suspension of the tariff be further extended for 60 days.

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 April 1, 2003, meeting, the Commission considered this matter. MDU concurred with Staff's recommendation. The Commission voted unanimously to grant the extension sought by Commission Staff. It is therefore

ORDERED, that the proposed schedule of rates shall be further suspended for 60 days pursuant to SDCL 49-34A-14.

Dated at Pierre, South Dakota, this 8th day of April, 2003.

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: 4/9/03

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

Robert K. Sahr

ROBERT K. SAHR, Chairman

Gary Hanson

GARY HANSON, 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
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(605) 773-3201
(605) 773-3809 fax

Transportation/Warehouse
(605) 773-5280
(605) 773-3225 fax

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1-800-332-1782

April 23, 2003

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

Mr. Douglas W. Schulz
Senior Attorney
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 Application of Montana-Dakota Utilities Co. for Authority to Increase Rates for Natrual Gas Service
Docket NG02-011

Gentlemen:

Enclosed each of you will find copies of Testimony of Martin C. Bettmann, Basil L. Copeland Jr., Michele M. Farris, David A. Jacobson, Keith A. Senger and Robert G. Towers. This is intended as service upon you by mail.

Very truly yours,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

cc: Mr. Robert G. Towers
Mr. Dave Peterson
Mr. Basil L. Copeland Jr.

CERTIFICATE OF SERVICE

I hereby certify that copies of Testimony of Martin C. Bettmann, Basil L. Copeland Jr., Michele M. Farris, David A. Jacobson, Keith A. Senger 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 23rd day of April, 2003.

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

Mr. Douglas W. Schulz
Senior Attorney
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

Karen E. Cremer

Karen E. Cremer
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

RECEIVED

APR 2 2 2003

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE

PUBLIC UTILITIES COMMISSION

STATE OF SOUTH DAKOTA

MONTANA- DAKOTA UTILITIES

DOCKET NO. NG02-011

TESTIMONY & EXHIBITS OF MARTIN C. BETTMANN

ON BEHALF OF THE COMMISSION STAFF

APRIL 2003

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES
DOCKET NO. NG02-011

TESTIMONY & EXHIBITS OF MARTIN C. BETTMANN
ON BEHALF OF THE COMMISSION STAFF
APRIL 2003

1 **Q. What is your name and by whom are you employed?**
2 A. My name is Martin C. Bettmann and I am employed as a Staff Engineer by the South
3 Dakota Public Utilities Commission (Commission). My business address is South Dakota
4 Public Utilities Commission, 500 East Capitol Avenue, Pierre, South Dakota, 57501-
5 5070.
6 **Q. Please describe your education and work experience.**
7 A. I received my Bachelor of Science degree in Engineering from South Dakota State
8 University in 1975. After graduation I was employed by an engineering consulting firm in
9 Aberdeen, South Dakota, prior to taking my present position as a Staff Engineer with the
10 Commission in November 1977.
11 **Q. Please describe what your job involves?**
12 A. Currently, my primary responsibility with the Commission Staff (Staff) is managing the
13 pipeline safety inspection program. While working for the Commission, I have also been
14 responsible for reviewing energy conversion and transmission facility siting applications,
15 evaluating and making recommendations on electric and natural gas rates and tariffs,
16 and advising the Staff on various engineering and technical matters that come before the
17 Commission.
18 **Q. Have you previously filed testimony in other electric or natural gas rate**
19 **proceedings before the Commission?**
20 A. Yes, I provided prefiled testimony on behalf of the Staff in four electric and five natural
21 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 and addresses the Company's proposed alternative Distribution Delivery Stabilization Mechanism (DDSM).

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 normalzation 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 36,162 Dekatherms booked as a sale in June 2002 for Ellsworth Air Force Base was actually used in May 2002, therefore the actual and normal HDD values used to determine the "June 2002" weather normalization adjustment were from the month of April 2002. The Company used HDD values based on the billing cycles of the Residential and Firm Service Customers, which are not exactly, but closer to, a two month average of the current and preceding month. The values are not exactly equal to the two-month average because they are based on the actual billing cycles, which do not necessarily correspond exactly to a full month. That is to say that a meter read on the 1st of one month may not be read on the 1st of the following month, but on the 2nd or 3rd causing a mismatch between the period when the energy was used and weather normalization period.

Q. In your opinion, what should be the amount of the weather normalization adjustment?

A. I have calculated a weather normalization adjustment of ($20,407).

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 Small and Large Meter Residential customers?**

A. The Company is proposing several significant rate design changes for its Residential customers. First of all they are proposing to combine the Small and Large Residential rates into a single rate. The Company's only reason for merging the two groups is the fact there are only a small number of Large Meter residential customers compared to the

number of Small Meter residential customers. The Company is also proposing to eliminate the two-step declining block rate structure that is presently in place.

The most significant proposed change for this customer class is an increase in the Basic Service Charge from $7.00 per month to a daily charge of $0.42 per day. The daily charge of $0.42 is equivalent to an average monthly charge of $12.77. Large Meter Residential service customers would actually have their Basic Service Charge decreased from $14.00 to $12.77 per month. As proposed by the Company these changes in the Basic Service Charge would allow it to recover approximately 80 percent of its customer related costs through the Basic Service Charge.

Q. **What rate design changes does the Staff propose for Small and Large Meter Residential customers?**

A. Staff is proposing to keep the basic rate design structure. It is my opinion that the Basic Service Charge and the Non-Gas Commodity Charge for both Small and Large Meter residential customers should not be changed. Staff Witness Towers' has recommended that none of the rate increase recommended by Staff be assigned to the Residential service class and Staff Witness Towers' has also calculated in Exhibit No.___(RGT-4) a Customer cost per bill for residential customers that is less than the current Basic Charge for the Small Meter residential customers.

Q. **What rate design changes does the Company propose for Small and Large Meter Firm General Service customer classes?**

A. The design changes the Company is proposing for the Small and Large Meter Firm General Service classes are similar to those described previously for the Small and Large Residential Service classes. In this case the Company is proposing to maintain the Small and Large Meter rate classes. As with the residential class, the Company is proposing to increase the Basic Service Charge to a level at which approximately 89 percent of the customer related costs would be recovered through the basic service charge. To reach their goal, the Company is proposing to increase the Basic Customer Charge for Small Meter Firm General Service customers by over 250 percent from $7.50 to $27.36 per month. The Basic Customer Charge for Large Meter Firm Service customers would be increased by the same percentage from $15.00 to $54.72 per month. Once again, the declining block rate structure would be eliminated.

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 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 remain at $7.50. The Basic Service Charge for the Large Meter Residential customers would also remain at $15.00 per month. The proposed increased in annual revenues of $249,236 for this revenue class would be made up by an increase in the Non-Gas Commodity Charge to $1.373 for the first block and $0.874 for the second block. The difference between the Non-Gas Commodity Charges is the same as the difference between the two blocks in the current rates. 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 two-step declining-block 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;	
$250.00 per month	$0.059 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;		
$40.00 per month	$0.484 per dk	$0.131 per dk
Proposed Rate by Company;		
$175.00 per month	$0.304 per dk	$0.131 per dk
Proposed Rate by Staff:		
$80.00 per month	$0.330 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;		
$300.00 per month	$0.141 per dk	$0.090 per dk
Proposed Rate by Staff:		
$150.00 per month	$0.177 per dk	$0.090 per dk

Small Interruptible General Gas Transportation Service Rate 81				
Base Rate	Nomination Charge	Commodity Charge Max. Rate Per Dk	Commodity Charge Min. Rate Per Dk	Balancing Charge per Dk
Current Rate;				
$40.00	$50.00	$0.484 per dk	$0.131 per dk	$0.342 per dk
Proposed Rate by Company;				
$225.00	Eliminated	$0.304 per dk	$0.131 per dk	$0.300 per dk
Proposed Rate by Staff:				
$90.00	Eliminated	$0.330 per dk	$0.131 per dk	$0.342 per dk

Large Interruptible General Gas Transportation Service Rate 82				
Base Rate	Nomination Charge	Commodity Charge Max. Rate Per Dk	Commodity Charge Min. Rate Per Dk	Balancing Charge per Dk

Current Rate;				
$150.00	$50.00	$0.177 per dk	$0.090 per dk	$0.342 per dk
Proposed Rate by Company;				
$350.00	Eliminated	$0.141 per dk	$0.090 per dk	$0.300 per dk
Proposed Rate by Staff:				
$200.00	Eliminated	$0.177 per dk	$0.090 per dk	$0.342 per dk

The Company is proposing to keep the revenue requirements for these customers at the current test year level. It is also Staff Witness Towers' opinion that the revenue requirement for these customer classes should remain at the test year levels. It is my opinion that the Base Rate for the Small Interruptible (Rate 71) customers should be increased to $80.00 per month. This increase is supported by the Customer Cost Analysis of Staff Witness Towers' Exhibit No.___(RGT-4). The Commodity Charge has been adjusted from $0.484 to $0.330 per Dekatherm to offset the increase in revenues from the increase in the Basic Charge.

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. First of all there were two customers that were reclassified during the test year. That means that they switched from receiving service under one rate to another. In these two instances one Small Interruptible (Rate 71) and one Small Interruptible Transportation (Rate 81) customer were both switched to Rate 70, the Firm General Service rate.

Two customers were cut out of service. I subtracted the volumes and revenues from these former customers from my rate analysis because they stopped receiving gas service during the test year, and it is my opinion that this was the more accurate way to show sales levels going forward.

Q. Did you reclassify any other customers in any manner as part of your heating degree-day analysis and rate comparison calculations?

A. Yes I did. The Company included one of its Rate 71 customers, which in my opinion does not have the typical weather sensitive load pattern, in with the normalization analysis of the weather sensitive customers in this rate class. This customer is a water slide operation that received service only during the months of June, July, August, and

September. There is no evidence of a "weather sensitive" winter heating load for this customer that should be normalized. The sales volumes and customer charge amounts were included with the other Non Weather Sensitive Customer shown in Exhibit (MCB-2) Schedule 1.

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 Small and Large Meter residential and Firm Commercial customers. I did not calculate typical bills for the Interruptible and Transportation customers. Exhibit____(MCB-7) does show the overall percent increase for the customer groups within the Interruptible and Transportation customer classes.

Q. What is your understanding of the reasons why Company Witness Feingold has proposed a DDSM?

A. It my understanding that the Company is proposing the adoption of a DDSM as an alternative only if the basic service charges for residential and firm general service customers are not raised to a level that would allow recovery of the full cost of service for those customer classes. The DDSM would correct for the over and under collection of distribution delivery revenues due to weather fluctuations. It is apparently the Company's opinion that it cannot recover the full cost of service when a portion of that cost is recovered through weather sensitive volumetric rates. Company Witness Feingold also contends, "[E] rratic financial results from the constant over and under recovery of distribution margin can adversely impact Montana-Dakota's outlook in the financial community and, ultimately could increase the Company's financing costs."

Q. As proposed by the Company, what is your understanding of how the DDSM would be implemented?

A. As I understand the DDSM proposed by the Company, at the end of each heating season the difference in revenues based on the difference between the actual and normal heating use would be calculated. Then the estimated total firm sales for the residential and Firm General Service for the following year would be estimated. The Adjustment Per Dekatherm for the following year would be determined by dividing the difference in revenues from the preceding year by the estimated firm sales for the following year. The same formula would be followed in subsequent years with addition of a true-up feature to adjust for any over or under collections in the prior year.

Q. Based on your education and experience, is it your opinion that the DDSM should be adopted as proposed by the Company?

A. No, I do not agree with the Company's proposal for the following reasons:

1. The time lag between when the revenues are collected or dispersed and when the true up occurs is too great. After each heating season, the under or over recovery of fixed costs would be collected or dispersed during the following year. During that time customers may have moved on or off the system and those true-up amounts will end up being charged or credited to customers not responsible for those expenses or credits. A part of this concern with the time lag is the customers' perception that the Company is holding their money and they are not being compensated for it.

2. Another concern that I have with the proposed DDSM is in the fact that after a warmer than normal heating season it would be normal for a positive adjustment to be calculated for the following heating season. If the following heating season is colder than normal, that customers would not only be stuck with the cost of the DDSM adjustment but also with the cost of purchasing larger volumes of energy, probably at higher prices.

3. It is also possible that due to variations in the weather in different parts of the Company's service area, customers in one area maybe experiencing a colder or warmer heating season than in other areas and therefore those customers could receive or pay an unfair share of the DDSM adjustment.

Q. Is a DDSM the only way that a company can try to stabilize its revenue flow to account for variations in weather?

A. No. One other option is weather hedging. Weather hedging can be characterized as a type of insurance that a utility can purchase to protect itself financially against the possibility of a warmer than normal heating season or spikes in energy costs.

Q. Has the issue of DDSM ever been considered and approved by the Commission?

A. In Docket NG92-003 Minnegasco requested the approval of the addition of a "Weather Normal Adjustment" (WNA) clause to its tariffs. As proposed, Minnegasco's WNA would have worked in a similar manner as the proposed DDSM proposed by the Company in this docket.

1 Based on the results of a public input hearing and feedback received by the Commission
2 from a bill insert in which Minnegasco attempted to explain the WNA, Minnegasco
3 requested that its application for the approval of the WNA tariff be withdrawn.
4 Q. **Does this conclude your testimony?**
5 A. Yes.

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization Adjustment
Test Year Ending June 30, 2002

Pro Forma Adjustment - Weather Normalization

Line No.	Description (a)	Total (b)
1	BILLED	
2	SMALL METER RESIDENTIAL	64,886
3	LARGE METER RESIDENTIAL	135
4	SMALL METER FIRM COMMERCIAL	6,726
5	LARGE METER FIRM COMMERCIAL	13,960
6	SMALL INTERRUPTIBLE	188
7	SMALL INTERRUPTIBLE TRANSPORTATION	866
8	ELLSWORTH AIR FORCE BASE	267
9	TOTAL BILLED	$ 87,028
8	UBILLED	
9	SMALL METER RESIDENTIAL	(66,188)
10	LARGE METER RESIDENTIAL	(148)
11	SMALL METER FIRM COMMERCIAL	(11,104)
12	LARGE METER FIRM COMMERCIAL	(29,439)
13	SMALL INTERRUPTIBLE	(555)
14	TOTAL UNBILLED	$ (107,434)
15	TOTAL	**$ (20,407)**

Sources:
Lines 2-6: Column(C), Exhibit___(MCB-1), Schedule 2
Lines 9-13: Column (F), Ehibit___(MCB-1), Schedule 3

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending June 30, 2002

SOUTH DAKOTA
BILLLED SALES

LINE NO.	RATE CLASS (A)	DEKATHERMS ADJUSTED (B)	MARGIN REVENUES (C)
1	SMALL METER RESIDENTIAL	50,047	$ 64,886
2	LARGE METER RESIDENTIAL	134	$ 135
3	SMALL METER FIRM COMMERCIAL	6,527	$ 6,726
4	LARGE METER FIRM COMMERCIAL	17,077	$ 13,960
5	SMALL INTERRUPTIBLE	388	$ 188
6	SMALL INTERRUPTIBLE TRANSPORTATION	1,789	$ 866
7	ELLSWORTH AIR FORCE BASE	4,300	$ 267
8	TOTAL		**$ 87,028**
9	WEATHER NORMALIZATION GAS REVENUES (BILLED + UNBILLED)		**$ (20,407)**

Sources:
Column (B) Lines 1-4, and 7: Exhibit____(MCB-1) Schedule 6-1 Column (L)
Column (B) Line 5: Exhibit____(MCB-2) Schedule 1 Column (G)
Column (B) Line 6: Exhibit____(MCB-3) Schedule 1-1 Column (L)
Column (F) Lines 1-7: Column (B) * Current Commodity Rates

Montan-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending June 30, 2002

UNBILLED TO APPLY TO REVENUE
FOR PERIOD ENDING JUNE 30, 2002
CURRENT RATES

Line No.		(A) DEKATHERMS UNBILLED	(B) BOOKED UNBILLED REV $	(C) NORMALIZED UNBILLED THERMS	(D) NORMALIZED UNBILLED REV $	(E) NORMALIZED UNBILLED THERM ADJUSTMENT	(F) NORMALIZED UNBILLED ADJ. REV $	(G) ANNUALIZED PRO FORMA
1	SMALL METER RESIDENTIAL	21,176	$ 91,089	19,206	$ 24,901	(1,970)	$ (66,188)	
2	LARGE METER RESIDENTIAL	76	$ 217	69	$ 69	(7)	$ (148)	
3	SMALL METER FIRM COMMERCIAL	2,680	$ 13,617	2,438	$ 2,513	(242)	$ (11,104)	
4	LARGE METER FIRM COMMERCIAL	9,672	$ 36,647	8,817	$ 7,208	(854)	$ (29,439)	
5	SMALL INTERRUPTIBLE	145	$ 915	1,219	$ 360	1,074	$ (555)	
6	EAFB & LARGE INTERRUPTIBLE							
7	SMALL & LARGE INTERRUPTIBLE TRANSPORTATION		$ 25,113		$ 25,113		$ -	
8	(EXCLUDED FROM NORMALIZATION)							
9		33,747	$ 167,598	31,749	$ 60,164	(1,998)	$ (107,434)	**$ (107,434)**

Sources:

Column (A): Exhibit ____ (MCB-1) Schedule 4 Column (B)
Column (B): Statement N Part A Page 10
Column (C): Exhibit ___ (MCB-1) Schedule 4 Column (C)
Column (D): Exhibit ___ (MCB-1) Schedule 5
Column (E): Column (C) - Column (A)
Column (F): Column (D) - Column (B)

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization
Test Year Ending June 30, 2002

NORMAILIZED UNBILLED DEKATHERMS
SOUTH DAKOTA
TEST YEAR ENDED JUNE 30, 2002

LINE NO.	RATE CLASS (A)		UNBILLED THERM'S (B)	NORMALIZED UNBILLED THERM'S (C)	NORMALIZED ADJUSTMENT COL (C) - COL (B) (D)
1	SMALL METER RESIDENTIALUNBILLED SALES	JUN-01	(34,255)	(34,071)	184
2	SMALL METER RESIDENTIALUNBILLED SALES	JUN-02	55,431	53,278	(2,153)
			21,176	19,206	(1,970)
3	LARGE METER RESIDENTIALUNBILLED SALES	JUN-01	(134)	(134)	(0)
4	LARGE METER RESIDENTIALUNBILLED SALES	JUN-02	210	203	(7)
5			76	69	(7)
5	SMALL METER FIRM UNBILLED SALES	JUN-01	(5,003)	(4,973)	30
6	SMALL METER FIRM UNBILLED SALES	JUN-02	7,682	7,411	(271)
			2,680	2,438	(242)
7	LARGE METER FIRM UNBILLED SALES	JUN-01	(25,568)	(25,428)	140
8	LARGE METER FIRM UNBILLED SALES	JUN-02	35,240	34,246	(994)
			9,672	8,817	(854)
7	SMALL INTERRUPTIBLE	JUN-01	(1,230)	(292)	939
8	SMALL INTERRUPTIBLE	JUN-02	1,375	1,511	136
			145	1,219	1,074
60	TOTAL UNBILLED SALES		33,747	31,749	(1,998)

Sources:

Column (B): Exhibit ___ (MCB-1) Schedule 6-2 Column (B)
Column (C): Exhibit ___ (MCB-1) Schedules 6-2 Column (I)

Montana-Dakota Utilities
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Weather Normalization
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UNBILLED NORMALIZED
TEST YEAR ENDED JUNE 30, 2002
BASED ON CURRENT RATES

Line No.	Rate	Period	Total Usage DekaTherms (A)	First Step Percentage (B)	Second Step Percentage (C)	Usage First Step (D)	Usage Second Step (E)	First Step Rate (F)	Second Step Rate (G)	Margin Revenue First Step (H)	Margin Revenue Second Step (I)	Margin Total Normalization (J)
1	Small Meter Residential	JUN-01 Reversal	(34,071)	0.80104	0.19896	(27,292)	(6,779)	1.396	0.896	($38,100)	($6,074)	($44,174)
2	Small Meter Residential	JUN-02 Accrual	53,278	0.80104	0.19896	42,678	10,600	1.396	0.896	$59,578	$9,498	$69,076
3	Total Unbilled Sales Normalized		19,206									$24,901
4	Large Meter Residential	JUN-01 Reversal	(134)	0.22368	0.77632	(30)	(104)	1.396	0.896	($42)	($93)	($135)
5	Large Meter Residential	JUN-02 Accrual	203	0.22368	0.77632	45	158	1.396	0.896	$63	$141	$205
6	Total Unbilled Sales Normalized		69									$69
7	Small Meter Commercial	JUN-01 Reversal	(4,973)	0.55031	0.44969	(2,737)	(2,236)	1.255	0.756	($3,434)	($1,691)	($5,125)
8	Small Meter Commercial	JUN-02 Accrual	7,411	0.55031	0.44969	4,078	3,333	1.255	0.756	$5,118	$2,519	$7,638
9	Total Unbilled Sales Normalized		2,438									$2,513
10	Large Meter Commercial	JUN-01 Reversal	(25,428)	0.12321	0.87679	(3,133)	(22,295)	1.255	0.756	($3,932)	($16,855)	($20,787)
11	Large Meter Commercial	JUN-02 Accrual	34,246	0.12321	0.87679	4,219	30,026	1.255	0.756	$5,295	$22,700	$27,995
12	Total Unbilled Sales Normalized		8,817									$7,208
13	Small Interruptible	JUN-01 Reversal	(1,225)			(1,225)		0.484		($593)		($593)
14	Small Interruptible	JUN-02 Accrual	1,968			1,968		0.484		$952		$952
15	Total Unbilled Sales Normalized		743									$360
16	TOTAL UNBILLED SALES NORMALIZED											**$35,051**

Sources:
Column (A): Exhibit ___ (MCB-1) Schedule 6-2 Column (I); Exhibit____(MCB-2) Schedule 2 Column (I) Adjusted for Unbilled Amounts
Column (B) and (C):Ratios based on Bill Frequency Report - Statement I workpapers (Response to Data request No. 1-2
Column (D): Column (A) * Column (B)
Column (E): Column (A) * Column (C)
Column (F) and (G): Current Tariffed Rates
Column (H): Column (D) * Column (F)
Column (I): Column (E) * Column (G)
Column (J): Column (H) + Column (I)

Montana-Dakota Utilities
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WEATHER STATION: Rapid City
REVENUE CLASS : RESIDENTIAL - SMALL METERS

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
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)
1	JUL	2001	34,278	68,510	68,510	-	49.4	55.9	0.00000	-	68,510	-
2	AUG	2001	34,328	61,193	61,193	-	6.9	0.5	0.00000	-	61,193	-
3	SEP	2001	34,514	66,967	66,967	-	88.2	64.1	0.00000	-	66,967	-
4	OCT	2001	34,825	134,934	66,418	68,516	273.9	247.1	1.10846	75,947	142,365	7,431
5	NOV	2001	35,017	225,914	66,784	159,130	726.1	578.0	1.25625	199,907	266,691	40,777
6	DEC	2001	35,137	368,490	67,013	301,477	1,086.0	938.6	1.15705	348,824	415,837	47,347
7	JAN	2002	35,243	479,975	67,215	412,760	1,275.0	1,142.7	1.11578	460,548	527,764	47,789
8	FEB	2002	35,285	429,024	67,295	361,729	1,255.1	1,096.3	1.14486	414,128	481,423	52,399
9	MAR	2002	35,336	473,644	67,393	406,251	973.5	1,117.9	0.87078	353,757	421,150	(52,494)
10	APR	2002	35,242	357,474	67,213	290,261	763.7	994.0	0.76835	223,021	290,235	(67,239)
11	MAY	2002	35,200	230,370	67,133	163,237	496.9	572.9	0.86733	141,580	208,713	(21,657)
12	JUN	2002	35,121	110,862	66,983	43,879	219.2	243.0	0.90185	39,573	106,555	(4,307)
13			419,526	3,007,357	800,118	2,207,239				2,257,285	3,057,404	50,047

REVENUE CLASS : RESIDENTIAL - 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)
14	JUL	2001	17	268	268	-	49.4	55.9	0.00000	-	268	-
15	AUG	2001	17	283	283	-	6.9	0.5	0.00000	-	283	-
16	SEP	2001	18	272	272	-	88.2	64.1	0.00000	-	272	-
17	OCT	2001	18	491	285	206	273.9	247.1	1.10846	228	513	22
18	NOV	2001	18	662	285	377	726.1	578.0	1.25625	474	759	97
19	DEC	2001	18	977	285	692	1,086.0	938.6	1.15705	801	1,086	109
20	JAN	2002	19	1,259	301	958	1,275.0	1,142.7	1.11578	1,069	1,370	111
21	FEB	2002	19	1,121	301	820	1,255.1	1,096.3	1.14486	939	1,240	119
22	MAR	2002	19	1,194	301	893	973.5	1,117.9	0.87078	778	1,079	(115)
23	APR	2002	18	926	285	641	763.7	994.0	0.76835	493	777	(149)
24	MAY	2002	18	637	285	352	496.9	572.9	0.86733	305	590	(47)
25	JUN	2002	18	419	285	134	219.2	243.0	0.90185	121	406	(13)
26			217	8,509	3,434	5,075				5,208	8,643	134

27	BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING SEP	1.9072	/ RESIDENTIAL - SMALL METERS
28	BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING SEP	15.8269	/ RESIDENTIAL - LARGE METERS

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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)
29	JUL	2001	3,365	10,005	9,500	-	49.4	55.9	0.00000	-	9,500	-
30	AUG	2001	3,367	9,709	9,506	-	6.9	0.5	0.00000	-	9,506	-
31	SEP	2001	3,366	8,795	9,503	-	88.2	64.1	0.00000	-	9,503	-
32	OCT	2001	3,395	16,151	9,585	6,566	273.9	247.1	1.10846	7,278	16,863	712
33	NOV	2001	3,447	31,686	9,732	21,954	726.1	578.0	1.25625	27,580	37,312	5,626
34	DEC	2001	3,466	61,309	9,785	51,524	1,086.0	938.6	1.15705	59,616	69,401	8,092
35	JAN	2002	3,480	87,882	9,825	78,057	1,275.0	1,142.7	1.11578	87,094	96,919	9,037
36	FEB	2002	3,490	78,608	9,853	68,755	1,255.1	1,096.3	1.14486	78,715	88,568	9,960
37	MAR	2002	3,496	88,052	9,870	78,182	973.5	1,117.9	0.87078	68,080	77,950	(10,102)
38	APR	2002	3,489	65,408	9,850	55,558	763.7	994.0	0.76835	42,688	52,538	(12,870)
39	MAY	2002	3,490	35,371	9,853	25,518	496.9	572.9	0.86733	22,132	31,986	(3,385)
40	JUN	2002	3,485	15,364	9,839	5,525	219.2	243.0	0.90185	4,983	14,822	(542)
41			41,336	508,340	116,701	391,639				398,166	514,867	6,527

42 *BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING SEP 2.8232 / 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)
43	JUL	2001	1,260	51,136	51,136	-	49.4	55.9	0.00000	-	51,136	-
44	AUG	2001	1,260	49,540	49,540	-	6.9	0.5	0.00000	-	49,540	-
45	SEP	2001	1,268	45,896	45,896	-	88.2	64.1	0.00000	-	45,896	-
46	OCT	2001	1,277	73,615	49,412	24,203	273.9	247.1	1.10846	26,828	76,240	2,625
47	NOV	2001	1,284	112,805	49,683	63,122	726.1	578.0	1.25625	79,297	128,980	16,175
48	DEC	2001	1,296	176,371	50,147	126,224	1,086.0	938.6	1.15705	146,047	196,195	19,824
49	JAN	2002	1,293	234,947	50,031	184,916	1,275.0	1,142.7	1.11578	206,325	256,356	21,409
50	FEB	2002	1,296	212,041	50,147	161,894	1,255.1	1,096.3	1.14486	185,345	235,493	23,452
51	MAR	2002	1,297	235,319	50,186	185,133	973.5	1,117.9	0.87078	161,211	211,397	(23,922)
52	APR	2002	1,296	184,449	50,147	134,302	763.7	994.0	0.76835	103,191	153,338	(31,111)
53	MAY	2002	1,302	121,128	50,379	70,749	496.9	572.9	0.86733	61,362	111,742	(9,386)
54	JUN	2002	1,298	70,479	50,225	20,254	219.2	243.0	0.90185	18,267	68,491	(1,988)
55			15,427	1,567,726	596,929	970,797				987,874	1,584,803	17,077

56 *BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING SEP 38.6938 / FIRM GENERAL SERVICE - LARGE METERS

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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)
57	JUL	2001	1	10,671	7,636	3,035	88.0	127.0	0.69291	2,103	9,739	(932)
58	AUG	2001	1	7,161	7,161	-	16.0	9.0	0.00000	-	7,161	-
59	SEP	2001	1	6,699	6,699	-	21.0	-	0.00000	-	6,699	-
60	OCT	2001	1	9,049	9,049	-	190.0	138.0	1.37681	-	9,049	-
61	NOV	2001	1	39,626	7,636	31,990	521.0	523.0	0.99618	31,867	39,504	(122)
62	DEC	2001	1	56,251	7,636	48,615	934.0	746.0	1.25201	60,866	68,502	12,251
63	JAN	2002	1	88,084	7,636	80,448	1,233.0	1,111.0	1.10981	89,282	96,918	8,834
64	FEB	2002	1	89,420	7,636	81,784	1,314.0	1,149.0	1.14360	93,528	101,164	11,744
65	MAR	2002	1	75,081	7,636	67,445	1,061.0	953.0	1.11333	75,088	82,724	7,643
66	APR	2002	1	98,929	7,636	91,293	925.0	1,316.0	0.70289	64,168	71,805	(27,124)
67	MAY	2002	1	56,116	7,636	48,480	595.0	606.0	0.98185	47,600	55,236	(880)
68	JUN	2002	1	36,162	7,636	28,526	313.0	417.0	0.75060	21,411	29,048	(7,114)
69			12	573,249	91,636	481,613				485,913	577,549	4,300

70 BASE LOAD = AVG SALES / CUST FOR 3 MO ENDING OCT 7,636.3333 / ELLSWORTH AFB

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 (I): Column (G) / Column (H)
Column (J): Column (F) * Column (I)
Coulmn (K): Column (E) + Column (J)
Column (L): Column (K) - Column (D)
Lines 27, 28, 42, 56 and 70: Exhibit ____ (MCB-1) Schedule 6-3

Montana-Dakota Utilities
South Dakota - Gas
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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 - SMALL METERS		
1	JUN	2001	34,278	(34,255)	(32,687)	(1,568)	49.4	55.9	0.88283	(1,384)	(34,071)	184
									RATE:	RESIDENTIAL - LARGE METERS		
2	JUN	2001	17	(134)	(135)	1	49.4	55.9	0.88283	0	(134)	(0)

3 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 0.953598 / RESIDENTIAL - SMALL METERS
4 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 7.913462 / RESIDENTIAL - LARGE METERS

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	JUN	2001	3,365	(5,003)	(4,750)	(252)	49.4	55.9	0.88283	(223)	(4,973)	30
									RATE:	FIRM GENERAL SERVICE - LARGE METERS		
6	JUN	2001	1,260	(25,568)	(24,377)	(1,191)	49.4	55.9	0.88283	(1,051)	(25,428)	140

7 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 1.4116 / FIRM GENERAL SERVICE - SMALL METERS
8 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 19.3469 / FIRM GENERAL SERVICE - LARGE METERS

Montana-Dakota Utilities
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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 - SMALL METERS		
1	JUN	2002	35,121	55,431	33,491	21,940	219.2	243.0	0.90185	19,786	53,278	(2,153)
									RATE:	RESIDENTIAL - LARGE METERS		
2	JUN	2002	18	210	142	67	219.2	243.0	0.90185	60	203	(7)

3 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 0.953598 / RESIDENTIAL - SMALL METERS
4 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 7.913462 / RESIDENTIAL - LARGE METERS

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	JUN	2002	3,485	7,682	4,919	2,763	219.2	243.0	0.90185	2,491	7,411	(271)
									RATE:	FIRM GENERAL SERVICE - LARGE METERS		
6	JUN	2002	1,298	35,240	25,112	10,127	219.2	243.0	0.90185	9,133	34,246	(994)

7 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 1.4116 / FIRM GENERAL SERVICE - SMALL METERS
8 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 19.3469 / FIRM GENERAL SERVICE - LARGE METERS

Column (A), (B), (E), and (F): Exhibit ___ (MCB-1) Schedule 6-3
Column (C): Column (A) * Base Load

Montana-Dakota Utilities
South Dakota - Gas
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STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	RESIDENTIAL - SMALL METERS CUSTOMERS (E)	RESIDENTIAL - SMALL METERS DEKATHERM SALES (F)	AVG USE 3 MONTH ENDING (G)	RESIDENTIAL - LARGE METERS CUSTOMERS (H)	RESIDENTIAL - LARGE METERS DEKATHERM SALES (I)	AVG USE 3 MONTH ENDING (J)
1	JUN	2001	88	127	N/A	N/A		N/A	N/A	
2	JUL	2001	16	9	34,278	68,510	3.9173	17	268	24.9811
3	AUG	2001	21	-	34,328	61,193	2.3192	17	283	18.6538
4	SEP	2001	190	138	34,514	66,967	1.9072	18	272	15.8269
5	OCT	2001	521	523	34,825	134,934	2.5379	18	491	19.7358
6	NOV	2001	934	746	35,017	225,914	4.0996	18	662	26.3889
7	DEC	2001	1,233	1,111	35,137	368,490	6.9475	18	977	39.4444
8	JAN	2002	1,314	1,149	35,243	479,975	10.1936	19	1,259	52.6909
9	FEB	2002	1,061	953	35,285	429,024	12.0900	19	1,121	59.9464
10	MAR	2002	925	1,316	35,336	473,644	13.0606	19	1,194	62.7018
11	APR	2002	595	606	35,242	357,474	11.9035	18	926	57.8750
12	MAY	2002	313	417	35,200	230,370	10.0351	18	637	50.1273
13	JUN	2002	88	44	35,121	110,862	6.6189	18	419	36.7037
14			7,211	7,012	419,526	3,007,357		217.0	8,509	

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 106 Number 6 to Volume 107 Number 6
Columns (E), (F), (H), (I), (K), (L), (N), (O), (Q), and (R): MDU Response to Staff Data Request No. 1-30

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LINE NO.	FIRM GENERAL SERVICE - SMALL METERS CUSTOMERS (K)	DEKATHERM SALES (L)	AVG USE 3 MONTH ENDING (M)	FIRM GENERAL SERVICE - LARGE METERS CUSTOMERS (N)	DEKATHERM SALES (O)	AVG USE 3 MONTH ENDING (P)	AIR FORCE BASE 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	3,365	10,005	5.8743	1,260	51,136	62.8868	1	10,671	34,316.3333
3	3,367	9,709	3.4333	1,260	49,540	44.8284	1	7,161	17,998.0000
4	3,366	8,795	2.8232	1,268	45,896	38.6938	1	6,699	8,177.0000
5	3,395	16,151	3.4217	1,277	73,615	44.4286	1	9,049	7,636.3333
6	3,447	31,686	5.5478	1,284	112,805	60.6728	1	39,626	18,458.0000
7	3,466	61,309	10.5885	1,296	176,371	94.0604	1	56,251	34,975.3333
8	3,480	87,882	17.4037	1,293	234,947	135.3274	1	88,084	61,320.3333
9	3,490	78,608	21.8282	1,296	212,041	160.4528	1	89,420	77,918.3333
10	3,496	88,052	24.3208	1,297	235,319	175.5808	1	75,081	84,195.0000
11	3,489	65,408	22.1545	1,296	184,449	162.4605	1	98,929	87,810.0000
12	3,490	35,371	18.0268	1,302	121,128	138.8693	1	56,116	76,708.6667
13	3,485	15,364	11.0993	1,298	70,479	96.5236	1	36,162	63,735.6667
14	41,336	508,340		15,427	1,567,726		12	573,249	

Montana-Dakota Utilities
South Dakota - Gas
Rate 71 Small Interruptible
Weather Normalization
Test Year Ending June 30, 2002

RATE 71 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	100	7,351	596	6,755	6,619	7,215	(136)
2	101	2,750	204	2,546	2,632	2,836	86
3	102	889	334	555	499	833	(56)
4	167	6,434	2,376	4,209	4,309	6,685	251
5	522	546	84	462	470	554	8
6	527	3,704	96	3,608	3,746	3,842	138
7	532	5,917	3,196	2,721	2,772	5,968	51
8	533	3,045	18	3,027	3,072	3,091	45
9	SUBTOTAL	30,636	6,904	23,883	24,120	31,024	388
None Weather Sensitive Customers							
10	556	2,312				2,312	
11	555	6,612				6,612	
12	540	1,502				1,502	
13	222	691				691	
14	574	393				393	
15	558	0				0	
16	SUBTOTAL	11,510				11,510	
17	TOTAL	42,146				**42,534**	

Sources:
Lines 1 - 8: Exhibit____(MCB-2) Schedule 3-1 to 10-1
Lines 10 - 15: Response to Data Request No. 2-12

Montana-Dakota Utilities
South Dakota - Gas
Rate 71 Small Interruptible
Weather Normalization Unbilled Sales
Test Year Ending June 30, 2002

WEATHER STATION: RAPID CITY APO

RATE: 71 SMALL INTERRUPTIBLE

LINE NO.	MONTH	YEAR	(A) NUMBER OF CUSTOMERS	(B) DKS 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	JUN	2001	6	(297)	(279)	(18)	88.0	127.0	0.69291	(13)	(292)	6
2	JUN	2002	7	918	326	593	88.0	44.0	2.00000	1,185	1,511	593

3 BASE LOAD = AVG SALES / CUSTOMER FOR JUL, AUG, & SEP TIMES PER MONTH = 46.500000 / RATE 71 - SMALL INTERRUPTIBLE

Sources:

Column (A): Response ro Data request No. 2-12
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 3-2, Actual and Normal HDD for June

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 100
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 100

	(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	JUL	2001	1	60	60	-	72	105	0.00000	-	60	-
2	AUG	2001	1	36	36	-	14	-	0.00000	-	36	-
3	SEP	2001	1	54	54	-	33	-	0.00000	-	54	-
4	OCT	2001	1	69	50	19	188	138	1.36232	26	76	7
5	NOV	2001	1	402	50	353	536	543	0.98711	348	398	(5)
6	DEC	2001	1	245	50	195	1,020	808	1.26238	246	296	51
7	JAN	2002	1	1,216	50	1,166	1,208	1,134	1.06526	1,242	1,292	76
8	FEB	2002	1	1,508	50	1,458	1,350	1,148	1.17596	1,715	1,764	257
9	MAR	2002	1	979	50	929	1,042	1,022	1.01957	947	997	18
10	APR	2002	1	1,408	50	1,358	847	1,166	0.72642	986	1,036	(371)
11	MAY	2002	1	668	50	619	585	617	0.94814	587	636	(32)
12	JUN	2002	1	708	50	658	316	399	0.79198	521	571	(137)
13			12	7,351	596	6,755				6,619	7,215	(136)

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. 100
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 100 CUSTOMERS (E)	CUSTOMER ID 100 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	JUN	2001	88	127	N/A	N/A	
2	JUL	2001	16	9	1	60	478.6000
3	AUG	2001	21	-	1	36	267.6667
4	SEP	2001	190	138	1	54	49.6667
5	OCT	2001	521	523	1	69	52.7000
6	NOV	2001	934	746	1	402	174.9667
7	DEC	2001	1,233	1,111	1	245	238.6333
8	JAN	2002	1,314	1,149	1	1,216	620.8000
9	FEB	2002	1,061	953	1	1,508	989.3000
10	MAR	2002	925	1,316	1	979	1,234.1000
11	APR	2002	595	606	1	1,408	1,298.0667
12	MAY	2002	313	417	1	668	1,018.2333
13	JUN	2002	88	44	1	708	927.7667
14			7,211	7,012	12	7,351	

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 106 Number 6 to Volume 107 Number 6
Columns (E) and (F): MDU Response to Staff Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 101
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 101

	(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	JUL	2001	1	18	18	-	47	65	0.00000	-	18	-
2	AUG	2001	1	16	16	-	5	-	0.00000	-	16	-
3	SEP	2001	1	17	17	-	68	39	0.00000	-	17	-
4	OCT	2001	1	96	17	79	249	216	1.15278	91	108	12
5	NOV	2001	1	169	17	152	714	593	1.20405	183	200	31
6	DEC	2001	1	370	17	353	1,050	893	1.17581	415	432	62
7	JAN	2002	1	502	17	485	1,248	1,096	1.13869	552	569	67
8	FEB	2002	1	460	17	443	1,322	1,188	1.11279	493	510	50
9	MAR	2002	1	482	17	465	985	1,104	0.89221	415	432	(50)
10	APR	2002	1	233	17	216	773	1,045	0.73971	160	177	(56)
11	MAY	2002	1	363	17	346	511	559	0.91413	316	333	(30)
12	JUN	2002	1	24	17	7	239	259	0.92278	6	23	(1)
13			12	2,750	204	2,546				2,632	2,836	86

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. 101
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 101 CUSTOMERS (E)	CUSTOMER ID 101 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	JUN	2001	88	127	N/A	N/A	
2	JUL	2001	16	9	1	18	135.0000
3	AUG	2001	21	-	1	16	19.3333
4	SEP	2001	190	138	1	17	17.0000
5	OCT	2001	521	523	1	96	43.0000
6	NOV	2001	934	746	1	169	94.0000
7	DEC	2001	1,233	1,111	1	370	211.6667
8	JAN	2002	1,314	1,149	1	502	347.0000
9	FEB	2002	1,061	953	1	460	444.0000
10	MAR	2002	925	1,316	1	482	481.3333
11	APR	2002	595	606	1	233	391.6667
12	MAY	2002	313	417	1	363	359.3333
13	JUN	2002	88	44	1	24	206.6667
14			7,211	7,012	12	2,750	

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 106 Number 6 to Volume 107 Number 6
Columns (E) and (F): MDU Response to Staff Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 102
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 102

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	JUL	2001	-	-	-	-	49	66	0.00000	-	-	-
2	AUG	2001	-	-	-	-	6	-	0.00000	-	-	-
3	SEP	2001	-	-	-	-	63	36	0.00000	-	-	-
4	OCT	2001	-	-	-	-	241	204	1.18137	-	-	-
5	NOV	2001	-	-	-	-	640	556	1.15108	-	-	-
6	DEC	2001	-	-	-	-	1,098	906	1.21192	-	-	-
7	JAN	2002	-	-	-	-	1,244	1,103	1.12783	-	-	-
8	FEB	2002	-	-	-	-	1,326	1,197	1.10777	-	-	-
9	MAR	2002	-	-	-	-	993	1,099	0.90355	-	-	-
10	APR	2002	0.3	184	48	136	782	1,060	0.73774	101	148	(36)
11	MAY	2002	1	562	143	419	520	547	0.95064	399	542	(21)
12	JUN	2002	1	143	143	(0)	249	278	0.00000	-	143	0
13			2	889	334	555				499	833	(56)

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. 102
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 527 CUSTOMERS (E)	CUSTOMER ID 527 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	JUN	2001	88	127	N/A	N/A	
2	JUL	2001	16	9	-	-	-
3	AUG	2001	21	-	-	-	-
4	SEP	2001	190	138	-	-	-
5	OCT	2001	521	523	-	-	-
6	NOV	2001	934	746	-	-	-
7	DEC	2001	1,233	1,111	-	-	-
8	JAN	2002	1,314	1,149	-	-	-
9	FEB	2002	1,061	953	-	-	-
10	MAR	2002	925	1,316	-	-	-
11	APR	2002	595	606	0	184	613.6667
12	MAY	2002	313	417	1	562	574.0769
13	JUN	2002	88	44	1	143	386.5652
14			7,211	7,012	2	889	

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 106 Number 6 to Volume 107 Number 6
Columns (E) and (F): MDU Response to Staff Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 167
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : RESIDENTIAL

	(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	JUL	2001	1	238	238	-	72	105	0.00000	-	238	-
2	AUG	2001	1	176	176	-	14	-	0.00000	-	176	-
3	SEP	2001	1	180	180	-	33	-	0.00000	-	180	-
4	OCT	2001	1	315	198	117	188	138	1.36232	159	357	42
5	NOV	2001	1	576	198	378	536	543	0.98711	373	571	(5)
6	DEC	2001	1	643	198	445	1,020	808	1.26238	562	760	117
7	JAN	2002	1	840	198	642	1,208	1,134	1.06526	684	882	42
8	FEB	2002	1	847	198	649	1,350	1,148	1.17596	763	961	114
9	MAR	2002	1	804	198	606	1,042	1,022	1.01957	618	816	12
10	APR	2002	1	707	198	509	847	1,166	0.72642	370	568	(139)
11	MAY	2002	1	664	198	617	585	617	0.94814	585	783	119
12	JUN	2002	1	444	198	246	316	399	0.79198	195	393	(51)
13			12	6,434	2,376	4,209				4,309	6,685	251

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. 167
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	Customer ID No. 167 CUSTOMERS (E)	Customer ID No. 167 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	JUN	2001	88	127	N/A	N/A	
2	JUL	2001	16	9	1	238	448.6667
3	AUG	2001	21	-	1	176	286.0000
4	SEP	2001	190	138	1	180	198.0000
5	OCT	2001	521	523	1	315	223.6667
6	NOV	2001	934	746	1	576	357.0000
7	DEC	2001	1,233	1,111	1	643	511.3333
8	JAN	2002	1,314	1,149	1	840	686.3333
9	FEB	2002	1,061	953	1	847	776.6667
10	MAR	2002	925	1,316	1	804	830.3333
11	APR	2002	595	606	1	707	786.0000
12	MAY	2002	313	417	1	664	725.0000
13	JUN	2002	88	44	1	444	605.0000
14			7,211	7,012	12	6,434	

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 106 Number 6 to Volume 107 Number 6
Columns (E) and (F): MDU Response to Staff Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 522
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 100

	(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	JUL	2001	1	13	13	-	60	68	0.00000	-	13	-
2	AUG	2001	1	3	3	-	7	-	0.00000	-	3	-
3	SEP	2001	1	5	5	-	58	36	0.00000	-	5	-
4	OCT	2001	1	28	7	21	233	199	1.17085	25	32	4
5	NOV	2001	1	44	7	37	625	537	1.16387	43	50	6
6	DEC	2001	1	59	7	52	1,087	894	1.21588	63	70	11
7	JAN	2002	1	67	7	60	1,240	1,116	1.11111	67	74	7
8	FEB	2002	1	72	7	65	1,252	1,110	1.12793	73	80	8
9	MAR	2002	1	83	7	76	1,014	1,048	0.96756	74	81	(2)
10	APR	2002	1	71	7	64	856	1,195	0.71632	46	53	(18)
11	MAY	2002	1	61	7	54	529	551	0.96007	52	59	(2)
12	JUN	2002	1	40	7	33	258	300	0.86000	28	35	(5)
13			12	546	84	462				470	554	8

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. 522
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 100 CUSTOMERS (E)	CUSTOMER ID 100 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	JUN	2001	88	127	N/A	N/A	
2	JUL	2001	16	9	1	13	38.0000
3	AUG	2001	21	-	1	3	18.6667
4	SEP	2001	190	138	1	5	7.0000
5	OCT	2001	521	523	1	28	12.0000
6	NOV	2001	934	746	1	44	25.6667
7	DEC	2001	1,233	1,111	1	59	43.6667
8	JAN	2002	1,314	1,149	1	67	56.6667
9	FEB	2002	1,061	953	1	72	66.0000
10	MAR	2002	925	1,316	1	83	74.0000
11	APR	2002	595	606	1	71	75.3333
12	MAY	2002	313	417	1	61	71.6667
13	JUN	2002	88	44	1	40	57.3333
14			7,211	7,012	12	546	

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 106 Number 6 to Volume 107 Number 6
Columns (E) and (F): MDU Response to Staff Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 527
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 527

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
LINE NO.	MONTH	YEAR	NUMBER OF CUSTOMERS	Dk 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	JUL	2001	1	9	9	-	49	66	0.00000	-	9	-
2	AUG	2001	1	6	6	-	6	-	0.00000	-	6	-
3	SEP	2001	1	9	9	-	63	36	0.00000	-	9	-
4	OCT	2001	1	163	8	155	241	204	1.18137	183	191	28
5	NOV	2001	1	339	8	331	640	556	1.15108	381	389	50
6	DEC	2001	1	493	8	485	1,098	906	1.21192	588	596	103
7	JAN	2002	1	691	8	683	1,244	1,103	1.12783	770	778	87
8	FEB	2002	1	530	8	522	1,326	1,197	1.10777	578	586	56
9	MAR	2002	1	542	8	534	993	1,099	0.90355	482	490	(52)
10	APR	2002	1	460	8	452	782	1,060	0.73774	333	341	(119)
11	MAY	2002	1	336	8	328	520	547	0.95064	312	320	(16)
12	JUN	2002	1	126	8	118	249	249	1.00000	118	126	-
13			12	3,704	96	3,608				3,746	3,842	138

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. 527
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 527 CUSTOMERS (E)	CUSTOMER ID 527 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	JUN	2001	88	127	N/A	N/A	
2	JUL	2001	16	9	1	9	157.0000
3	AUG	2001	21	-	1	6	47.0000
4	SEP	2001	190	138	1	9	8.0000
5	OCT	2001	521	523	1	163	59.3333
6	NOV	2001	934	746	1	339	170.3333
7	DEC	2001	1,233	1,111	1	493	331.6667
8	JAN	2002	1,314	1,149	1	691	507.6667
9	FEB	2002	1,061	953	1	530	571.3333
10	MAR	2002	925	1,316	1	542	587.6667
11	APR	2002	595	606	1	460	510.6667
12	MAY	2002	313	417	1	336	446.0000
13	JUN	2002	88	44	1	126	307.3333
14			7,211	7,012	12	3,704	

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 106 Number 6 to Volume 107 Number 6
Columns (E) and (F): MDU Response to Staff Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 532
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 532

	(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	JUL	2001	1	274	274	-	45	61	0.00000	-	274	-
2	AUG	2001	1	265	265	-	4	-	0.00000	-	265	-
3	SEP	2001	1	260	260	-	73	50	0.00000	-	260	-
4	OCT	2001	1	394	266	128	258	225	1.14667	146	413	19
5	NOV	2001	1	487	266	221	730	589	1.23939	273	540	53
6	DEC	2001	1	582	266	316	1,059	918	1.15359	364	630	48
7	JAN	2002	1	757	266	491	1,338	1,148	1.16551	572	838	81
8	FEB	2002	1	629	266	363	1,232	1,132	1.08834	395	661	32
9	MAR	2002	1	741	266	475	977	1,080	0.90463	429	696	(45)
10	APR	2002	1	651	266	385	764	1,047	0.72970	281	547	(104)
11	MAY	2002	1	522	266	256	524	600	0.87333	223	490	(32)
12	JUN	2002	1	355	266	89	207	208	0.99519	88	355	(0)
13			12	5,917	3,196	2,721				2,772	5,968	51

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)

Montan-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Customer ID No. 532
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 532 CUSTOMERS (E)	CUSTOMER ID 532 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	JUN	2001	88	127	N/A	N/A	
2	JUL	2001	16	9	1	274	383.6667
3	AUG	2001	21	-	1	265	298.0000
4	SEP	2001	190	138	1	260	266.3333
5	OCT	2001	521	523	1	394	306.3333
6	NOV	2001	934	746	1	487	380.3333
7	DEC	2001	1,233	1,111	1	582	487.6667
8	JAN	2002	1,314	1,149	1	757	608.6667
9	FEB	2002	1,061	953	1	629	656.0000
10	MAR	2002	925	1,316	1	741	709.0000
11	APR	2002	595	606	1	651	673.6667
12	MAY	2002	313	417	1	522	638.0000
13	JUN	2002	88	44	1	355	509.3333
14			7,211	7,012	12	5,917	

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 106 Number 6 to Volume 107 Number 6
Columns (E) and (F): MDU Response to Staff Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 533
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 533

	(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	JUL	2001	1	0	0	-	38	32	0.00000	-	0	-
2	AUG	2001	1	6	6	-	-	-	0.00000	-	6	-
3	SEP	2001	1	12	12	-	105	89	0.00000	-	12	-
4	OCT	2001	1	106	-	106	302	294	1.02721	109	109	3
5	NOV	2001	1	220	-	220	746	523	1.42639	314	314	94
6	DEC	2001	1	428	-	428	1,166	1,037	1.12440	481	481	53
7	JAN	2002	1	539	-	539	1,268	1,131	1.12113	604	604	65
8	FEB	2002	1	468	-	468	1,292	1,122	1.15152	539	539	71
9	MAR	2002	1	639	-	639	938	1,155	0.81212	519	519	(120)
10	APR	2002	1	360	-	360	717	880	0.81477	293	293	(67)
11	MAY	2002	1	246	-	246	453	577	0.78510	193	193	(53)
12	JUN	2002	1	21	-	21	186	197	0.94416	20	20	(1)
13			12	3,045	18	3,027				3,072	3,091	45

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. 533
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 533 CUSTOMERS (E)	CUSTOMER ID 533 DK THERM SALES (F)
1	JUN	2001	88	127	N/A	N/A
2	JUL	2001	16	9	1	0
3	AUG	2001	21	-	1	6
4	SEP	2001	190	138	1	12
5	OCT	2001	521	523	1	106
6	NOV	2001	934	746	1	220
7	DEC	2001	1,233	1,111	1	428
8	JAN	2002	1,314	1,149	1	539
9	FEB	2002	1,061	953	1	468
10	MAR	2002	925	1,316	1	639
11	APR	2002	595	606	1	360
12	MAY	2002	313	417	1	246
13	JUN	2002	88	44	1	21
14			7,211	7,012	12	3,045

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 106 Number 6 to Volume 107 Number 6
Columns (E) and (F): MDU Response to Staff Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Rate 81 Small Interruptible Transportation
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : RATE 81 - SMALL INTERRUPTIBLE TRANSPORTATION

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
LINE NO.	MONTH	YEAR	NUMBER OF CUSTOMERS	Dk 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	JUL	2001	19	4,689	4,689	-	88	127	0.00000	-	4,689	-
2	AUG	2001	19	3,968	3,968	-	16	9	0.00000	-	3,968	-
3	SEP	2001	19	5,025	5,025	-	21	-	0.00000	-	5,025	-
4	OCT	2001	19	5,243	4,561	682	190	138	1.37681	939	5,500	257
5	NOV	2001	19	14,560	4,561	9,999	521	523	0.99618	9,961	14,522	(38)
6	DEC	2001	19	20,483	4,561	15,922	934	745	1.25369	19,961	24,522	4,039
7	JAN	2002	19	29,962	4,561	25,401	1,233	1,111	1.10981	28,190	32,751	2,789
8	FEB	2002	19	31,749	4,561	27,188	1,314	1,149	1.14360	31,092	35,653	3,904
9	MAR	2002	19	26,999	4,561	22,438	1,061	954	1.11216	24,955	29,516	2,517
10	APR	2002	19	34,817	4,561	30,256	925	1,313	0.70449	21,315	25,876	(8,941)
11	MAY	2002	19	20,484	4,561	15,924	595	614	0.96906	15,431	19,992	(493)
12	JUN	2002	19	13,567	4,561	9,006	313	417	0.75060	6,760	11,321	(2,246)
13			228	211,546	54,730	156,816				158,605	213,335	1,789
14	Non-Weather Sensitive		149	221,161							221,161	
15	TOTAL		377	432,707							**434,496**	

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 2 Column (C) and (D)
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: Response to Data Request No. 2-12

Montana-Dakota Utilities
SouthDakota - Gas
Weather Normalization - Rate 81 Small Interruptible Transportation
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	Rate 81 Small Interruptible Transport CUSTOMERS (E)	Rate 81 Small Interruptible Transport DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	JUN	2001	88	127	N/A	N/A	
2	JUL	2001	16	9	19	4,689	679.6684
3	AUG	2001	21	-	19	3,968	389.9035
4	SEP	2001	190	138	19	5,025	240.0456
5	OCT	2001	521	523	19	5,243	249.7614
6	NOV	2001	934	745	19	14,560	435.5895
7	DEC	2001	1,233	1,111	19	20,483	706.7737
8	JAN	2002	1,314	1,149	19	29,962	1,140.4298
9	FEB	2002	1,061	954	19	31,749	1,441.9842
10	MAR	2002	925	1,313	19	26,999	1,556.3018
11	APR	2002	595	614	19	34,817	1,641.4807
12	MAY	2002	313	417	19	20,484	1,443.8632
13	JUN	2002	88	44	19	13,567	1,208.2193
14			7,211	7,017	228	211,546	

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 106 Number 6 to Volume 107 Number 6
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 June 30, 2002

Rate 81 Customer Usage by Month - DekaTherms

Line No.	Month	Customer ID Nos. 194	136	212	145	531	39	41	523	19.7	524	215
1	Jul-01	302.3	109.4	0	5.7	0	65.3	1394.8	0	405	0	19.8
2	Aug-01	260.2	110.4	0	27.1	0	51.9	1083.4	0	357	0	17.9
3	Sep-01	228.6	115.4	0	0	0	48.3	1095.7	0	331	0	19.1
4	Oct-01	337.9	143.9	0	23.5	0	97.1	1475.5	3.6	405	0.4	0
5	Nov-01	529.6	373.6	110.1	496.5	209.1	617.5	3217.9	788.4	986	36.2	140.6
6	Dec-01	635	527.1	260.7	582.1	364.4	741.6	4346.8	1361.1	1,480	81.3	373.5
7	Jan-02	748.5	728.1	198.5	1130.4	677.4	1234.6	6140.5	2223.5	1,483	209.2	599.7
8	Feb-02	783.4	764.6	442.4	1129.5	772.1	1269.4	5960.8	2354.8	1,460	224.8	527.4
9	Mar-02	702.7	620.5	228.2	942	586.6	1046.9	5087.5	1869.3	1,437	170.6	438.3
10	Apr-02	753.3	690	310.4	1090.6	775.3	1429.5	6653.9	2379.6	2,081	218.6	586.2
11	May-02	693.5	355	180.6	549.7	302.8	809.8	3990.1	1238.5	1,317	74	217.9
12	Jun-02	593.3	225.8	147.4	248.1	113.8	724	3036.3	495.8	928	29.3	233.5
13	TOTAL	6,568.3	4,763.8	1,878.3	6,225.2	3,801.5	8,135.9	43,483.2	12,714.6	12,670.4	1,044.4	3,173.9

Source:
Lines 1-12: Response to Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Usage Analysis
Rate 81 Small Interruptible Transportation
Test Year Ending June 30, 2002

Rate 81 Customer Usage by Month - DekaTherms

Line No.	Month	Customer ID Nos. 529	191	252	125	218	239	34	33	Total
1	Jul-01	70	399.3	0	802.9	233.9	695.9	62.9	121.8	4,689.4
2	Aug-01	0.1	249.9	0	553.4	157.4	343.8	690.5	65	3,967.8
3	Sep-01	2.1	256.8	0	636.7	170.8	272.1	1804.8	43.8	5,025.4
4	Oct-01	183.9	437.2	0	849.8	299.7	274.7	582.1	128.9	5,243.2
5	Nov-01	811.1	665	30.6	1239.2	451.8	792.1	1049.4	2015.2	14,560.0
6	Dec-01	1120.1	688.1	87.7	1276.7	521.4	758.3	1867.5	3409.6	20,482.9
7	Jan-02	1711	952.6	142.1	1500.6	658.2	1004.8	3258.6	5360.1	29,961.6
8	Feb-02	1769.3	1014.7	260.4	1625.4	657.5	1378.9	3732	5621.3	31,748.6
9	Mar-02	1486.6	886.2	191	1369.5	508	1432.9	3069.8	4925.5	26,999.0
10	Apr-02	2001.1	1316.2	204.4	1692.3	770.8	2406.7	3572.5	5884.2	34,816.8
11	May-02	999.2	984.2	57.8	1118.4	487.7	1880.4	1563.8	3663.7	20,484.4
12	Jun-02	638.2	858.1	11.5	1096.5	369	1520	830.3	1468.9	13,567.3
13	TOTAL	10,792.7	8,708.3	985.5	13,761.4	5,286.2	12,760.6	22,084.2	32,708.0	**211,546.4**

Source:
Lines 1-12: Response to Data Request No. 2-4

Montana-Dakota Utilities
South Dakota - Gas
Weather Normalization - Customer ID No. 212
Test Year Ending June 30, 2002

WEATHER STATION: Rapid City
REVENUE CLASS : CUSTOMER ID 212

	(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	JUL	2001	1	-	-	-	88	127	0.69291	-	-	-
2	AUG	2001	1	-	-	-	16	9	0.00000	-	-	-
3	SEP	2001	1	-	-	-	21	-	0.00000	-	-	-
4	OCT	2001	1	-	-	-	190	138	0.00000	-	-	-
5	NOV	2001	1	110	-	110	521	523	0.99618	110	110	(0)
6	DEC	2001	1	261	-	261	934	746	1.25201	326	326	66
7	JAN	2002	1	199	-	199	1,233	1,111	1.10981	220	220	22
8	FEB	2002	1	442	-	442	1,314	1,149	1.14360	506	506	64
9	MAR	2002	1	228	-	228	1,061	953	1.11333	254	254	26
10	APR	2002	1	310	-	310	925	1,316	0.70289	218	218	(92)
11	MAY	2002	1	181	-	181	595	606	0.98185	177	177	(3)
12	JUN	2002	1	147	-	147	313	417	0.75060	111	111	(37)
13			12	1,878	-	1,878				1,923	1,923	44

Sources:
Column (C), (D), (G), and (H): Exhibit____(MCB-4) Schedule 2
Column (E): Column (C) * Baseload
Column (F): Column (D) - Column (E)
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. 212
Test Year Ending June 30, 2002

STATE: SOUTH DAKOTA
WEATHER STATION; Rapid City APO

LINE NO.	MONTH (A)	YEAR (B)	DEGREE DAYS NORMAL (C)	DEGREE DAYS ACTUAL (D)	CUSTOMER ID 212 CUSTOMERS (E)	CUSTOMER ID 212 DK THERM SALES (F)	AVG USE 3 MONTH ENDING (G)
1	JUN	2001	88	127	N/A	N/A	
2	JUL	2001	16	9	1	-	109.3333
3	AUG	2001	21	-	1	-	49.1333
4	SEP	2001	190	138	1	-	-
5	OCT	2001	521	523	1	-	-
6	NOV	2001	934	746	1	110	36.7000
7	DEC	2001	1,233	1,111	1	261	123.6000
8	JAN	2002	1,314	1,149	1	199	189.7667
9	FEB	2002	1,061	953	1	442	300.5333
10	MAR	2002	925	1,316	1	228	289.7000
11	APR	2002	595	606	1	310	327.0000
12	MAY	2002	313	417	1	181	239.7333
13	JUN	2002	88	44	1	147	212.8000
14			7,211	7,012	12	1,878	

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 106 Number 6 to Volume 107 Number 6
Columns (E) and (F): MDU Response to Staff Data Request No. 2-4

MONTANA-DAKOTA UTILITIES
REVENUE INCREASE
COMPARISON

LINE NO.	REVENUE INCREASE by CUSTOMER CLASS	Dekatherms	Dekatherms	Test Year Revenue	Proposed Revenue	Revenue (Inc./Dec.)	Percent (Inc./Dec.)
1	RESIDENTIAL	3,085,321	3,085,321	$6,937,382	$6,937,382	$0	0.0%
2	FIRM GENERAL SERVICE	2,120,154	2,120,154	2,386,988	2,637,167	250,178	10.5%
3	FIRM CONTRACT SERVICE	625,741	625,741	219,558	219,558	0	0.0%
4	ELLSWORTH AIR FORCE BASE	577,549	577,549	36,948	36,948	0	0.0%
5	MISC. INTERRUPTIBLE TRANSPORT & OTHER REVENUES	1,327,974	1,327,974	451,922	385,331	(66,591)	-14.7%
6	TOTAL	7,736,740	7,736,740	$10,032,799	$10,216,386	$183,587	1.8%

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	PROPOSED	>--- RATE ($/UNIT) ---< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>--- CHANGE ---< AMOUNT
	Small Meter									
	Residential - Rate 600									
1		FIRST 10	DekaTherms	2,409,006	2,409,006	1.39600	1.39600	3,362,972	3,362,972	0
2		EXCESS	DekaTherms	598,351	598,351	0.89600	0.89600	536,122	536,122	(0)
3										
4										
5		CUSTOMER CHARGE	BILL	419,526	419,526	7.00	7.00	2,936,682	2,936,682	0
6										
7	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
8		SUB TOTAL	DekaTherms	3,007,357	3,007,357			6,835,777	6,835,777	0
9										
10	SMR Rate Unbilled JUN 01									
11										
12		FIRST 10	DekaTherms	0	0	1.39600	1.39600	0	0	0
13		EXCESS	DekaTherms	0	0	0.89600	0.89600	0	0	0
14										
15										
16		CUSTOMER CHARGE	BILL	0	0	7.00	7.00	0	0	0
17										
18		SUB TOTAL	DekaTherms	21,176	21,176			91,089	91,089	0
19										
20	SMR Rate Weather									
21										
22		FIRST 10	DekaTherms	40,089	40,089	1.39600	1.39600	55,965	55,965	0
23		EXCESS	DekaTherms	9,957	9,957	0.89600	0.89600	8,922	8,922	0
24										
25										
26		CUSTOMER CHARGE	BILL	0	0	7.00	7.00	0	0	0
27										
28	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
29		SUB TOTAL	DekaTherms	50,047	50,047			64,886	64,886	0
30										
31	SMR Rate Weather - Unbilled JUN 02									
32										
33		FIRST 10	DekaTherms	0	0	1.39600	1.39600	0	0	0
34		EXCESS	DekaTherms	0	0	0.89600	0.89600	0	0	0
35										
36										
37		CUSTOMER CHARGE	BILL	0	0	7.00	7.00	0	0	0
38										
39		SUB TOTAL	DekaTherms	(1,970)	(1,970)			(66,188)	(66,188)	0
40										
41	**TOTAL RESIDENTIAL - RATE 600**			**3,076,610**	**3,076,610**			**$ 6,925,565**	**$ 6,925,565**	**$ -**
42										

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 $) PROPOSED	CHANGE AMOUNT
43	**Large Meter**									
44	**Residential - Rate 601**									
45										
46		FIRST 10	DekaTherms	1,903	1,903	1.39600	1.39600	2,657	2,657	0
47		EXCESS	DekaTherms	6,606	6,606	0.89600	0.89600	5,919	5,919	(0)
48										
49										
50		CUSTOMER CHARGE	BILL	217	217	14.00	14.00	3,038	3,038	0
51										
52	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
53		SUB TOTAL	DekaTherms	8,509	8,509			11,614	11,614	(0)
54										
55	LMR Rate Unbilled JUN 01									
56										
57		FIRST 10	DekaTherms	0	0	1.39600	1.39600	0	0	0
58		EXCESS	DekaTherms	0	0	0.89600	0.89600	0	0	0
59										
60										
61		CUSTOMER CHARGE	BILL	0	0	14.00	14.00	0	0	0
62										
63		SUB TOTAL	DekaTherms	76	76			217	217	0
64										
65	LMR Rate Weather									
66										
67		FIRST 10	DekaTherms	30	30	1.39600	1.39600	42	42	0
68		EXCESS	DekaTherms	104	104	0.89600	0.89600	93	93	0
69										
70										
71		CUSTOMER CHARGE	BILL	0	0	14.00	14.00	0	0	0
72										
73	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
74		SUB TOTAL	DekaTherms	134	134			135	135	0
75										
76	LMR Rate Weather - Unbilled JUN 02									
77										
78		FIRST 10	DekaTherms	0	0	1.39600	1.39600	0	0	0
79		EXCESS	DekaTherms	0	0	0.89600	0.89600	0	0	0
80										
81										
82		CUSTOMER CHARGE	BILL	0	0	14.00	14.00	0	0	0
83										
84		SUB TOTAL	DekaTherms	(7)	(7)			(148)	(148)	0
85										
86	**TOTAL RESIDENTIAL - RATE 601**			**8,711**	**8,711**			**$ 11,818**	**$ 11,818**	**$ (0)**
87										
88		**TOTAL RESIDENTIAL**		**3,085,321**	**3,085,321**			**$ 6,937,382**	**$ 6,937,382**	**$ -**

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	PROPOSED	>---- RATE ($/UNIT) ----< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>---- CHANGE ----< AMOUNT
	Small Meter									
	Firm General Service - Rate 700									
1		FIRST 15	DekaTherms	279,746	279,746	1.25500	1.37300	351,081	384,091	33,010
2		EXCESS	DekaTherms	228,595	228,595	0.75600	0.87400	172,818	199,792	26,974
3										
4										
5		CUSTOMER CHARGE	BILL	41,337	41,337	7.50	7.50	310,028	310,028	0
6										
7		PURCHASED GAS ADJUSTMENT				0.00000	0.00000			
8		SUB TOTAL	DekaTherms	508,341	508,341			833,927	893,911	59,984
9										
10	SMFG Rate Unbilled JUN 01									
11										
12		FIRST 15	DekaTherms	0	0	1.25500	1.37300	0	0	0
13		EXCESS	DekaTherms	0	0	0.75600	0.87400	0	0	0
14										
15										
16		CUSTOMER CHARGE	BILL	0	0	7.50	7.50	0	0	0
17										
18		SUB TOTAL	DekaTherms	2,680	2,680			13,617	13,030	(587)
19										
20	SMFG Rate Weather Normalization									
21										
22		FIRST 15	DekaTherms	3,592	3,592	1.25500	1.37300	4,508	4,931	424
23		EXCESS	DekaTherms	2,935	2,935	0.75600	0.87400	2,219	2,565	346
24										
25										
26		CUSTOMER CHARGE	BILL	0	0	7.50	7.50	0	0	0
27										
28		PURCHASED GAS ADJUSTMENT				0.00000	0.00000			
29		SUB TOTAL		6,527	6,527			6,726	7,497	770

Montana-Dakota Utilities
South Dakota - Gas
Firm General Service Rates
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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 $) PROPOSED	CHANGE AMOUNT
30										
31	SMFG Rate Weather - Unbilled JUN 02									
32										
33		FIRST 15	DekaTherms	0	0	1.25500	1.37300	0	0	0
34		EXCESS	DekaTherms	0	0	0.75600	0.87400	0	0	0
35										
36										
37		CUSTOMER CHARGE	BILL	0	0	7.50	7.50	0	0	0
38										
39		SUB TOTAL		(242)	(242)			(11,104)	(10,230)	874
40										
41	SMFG Rate Weather - Reclassify Rate 71 and Rate 81									
42										
43		FIRST 15	DekaTherms	5,078	5,078	1.25500	1.37300	6,373	6,973	599
44		EXCESS	DekaTherms	4,150	4,150	0.75600	0.87400	3,137	3,627	490
45										
46										
47		CUSTOMER CHARGE	BILL	20	20	7.50	7.50	150	150	0
48										
49		SUB TOTAL - PER BOOKS		9,228	9,228			9,661	10,750	1,089
50										
41	**TOTAL FIRM GENERAL SERVICE - RATE 700**			**526,534**	**526,534**			**$ 852,826**	**$ 914,957**	**$ 62,131**
42										
43	**Lage Meter**									
44	**Firm General Service - Rate 701**									
45										
46										
47		FIRST 15	DekaTherms	193,163	193,163	1.25500	1.37300	242,420	265,213	22,793
48		EXCESS	DekaTherms	1,374,563	1,374,563	0.75600	0.87400	1,039,170	1,201,368	162,198
49										
50										
51		CUSTOMER CHARGE	BILL	15,427	15,427	15.00	15.00	231,405	231,405	0
52										
53		PURCHASED GAS ADJUSTMENT				0.00000	0.00000			
54		SUB TOTAL		1,567,726	1,567,726			1,512,994	1,697,986	184,992
55										
56	LMFG Rate Unbilled JUN 01									
57										
58		FIRST 15	DekaTherms	0	0	1.25500	1.37300	0	0	0
59		EXCESS	DekaTherms	0	0	0.75600	0.87400	0	0	0
60										
61										
62		CUSTOMER CHARGE	BILL	0	0	15.00	15.00	0	0	0
63										
64		SUB TOTAL - PER BOOKS		9,672	9,672			36,647	33,646	(3,001)
65										

Montana-Dakota Utilities
South Dakota - Gas
Firm General Service Rates
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LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	>---------- QUANTITY ----------< PRESENT	PROPOSED	>---- RATE ($/UNIT) ----< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>---- CHANGE ----< AMOUNT
66	LMFG Rate Weather Normalization									
67										
68		FIRST 15	DekaTherms	2,104	2,104	1.25500	1.37300	2,641	2,889	248
69		EXCESS	DekaTherms	14,973	14,973	0.75600	0.87400	11,320	13,086	1,767
70										
71										
72		CUSTOMER CHARGE	BILL	0	0	15.00	15.00	0	0	0
73										
74	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
75		SUB TOTAL		17,077	17,077			13,960	15,975	2,015
76										
77	LMFG Rate Weather - Unbilled JUN 02									
78										
79		FIRST 15	DekaTherms	0	0	1.25500	1.37300	0	0	0
80		EXCESS	DekaTherms	0	0	0.75600	0.87400	0	0	0
81										
82										
83		CUSTOMER CHARGE	BILL	0	0	15.00	15.00	0	0	0
84										
85	SUB TOTAL - PER BOOKS			(854)	(854)			(29,439)	(25,398)	4,041
86										
87	**TOTAL FIRM GENERAL SERVICE - RATE 701**			**1,593,620**	**1,593,620**			**$ 1,534,162**	**$ 1,722,209**	**$ 188,047**
88										
89	**TOTAL FIRM GENERAL SERVICE**			**2,120,154**	**2,120,154**			**$ 2,386,988**	**$ 2,637,167**	**$ 250,178**

Montana-Dakota Utilities
South Dakota Gas
Interruptible and Transportation and Other Rate Comparison
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LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	>—— QUANTITY ——< PRESENT	PROPOSED	>-- RATE ($/UNIT) --< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>-- INCREASE -- AMOUNT
	Firm Contract Service - Rate 702									
1		MIN BILLS	BILL			150.00	150.00			
2		MIN BILLS								
3		ALL	DekaTherms	623,061	623,061	0.34800	0.34800	216,825	216,825	0
4										
5	CUSTOMER CHARGE & MINNUM		BILL	12	12	150.00	150.00	1,800	1,800	0
6										
7	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
8		SUBTOTAL	DekaTherms	623,061	623,061			218,625	218,625	0
9										
10	Firm Contract Service - Rate 702 - Weather									
11										
12		MIN BILLS	BILL			150.00	150.00			
13		MIN BILLS								
14		ALL	DekaTherms	2,680	2,680	0.34800	0.34800	933	933	0
15										
16	CUSTOMER CHARGE & MINNUM		BILL	0	0	150.00	150.00	0	0	0
17										
18	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
19		SUBTOTAL	DekaTherms	2,680	2,680			933	933	0
20										
21	**TOTAL - Firm Contract Service - Rate 702**			**625,741**	**625,741**			**$ 219,558**	**$ 219,558**	**$ -**
22										

Montana-Dakota Utilities
South Dakota Gas
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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 $) PROPOSED	INCREASE AMOUNT
23	**Ellsworth Air Force Base**									
24										
25		MIN BILLS	BILL			95.00	95.00			
26		MIN BILLS								
27		ALL	DekaTherms	573,249	573,249	0.06200	0.06200	35,541	35,541	0
28										
29	CUSTOMER CHARGE & MINNUM		BILL	12	12	95.00	95.00	1,140	1,140	0
30										
31	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
32		SUBTOTAL	DekaTherms	573,249	573,249			36,681	36,681	0
33										
34	EAFB - Weather Normalization									
35										
36		MIN BILLS	BILL			95.00	95.00			
37		MIN BILLS								
38		ALL	DekaTherms	4,300	4,300	0.06200	0.06200	267	267	0
39										
40	CUSTOMER CHARGE & MINNUM		BILL	0	0	95.00	95.00	0	0	0
41										
42	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
43		SUBTOTAL	DekaTherms	4,300	4,300			267	267	0
44										
45	**TOTAL - Ellsworth Air Force Base**			**577,549**	**577,549**			**$ 36,948**	**$ 36,948**	**$ -**
46										

Montana-Dakota Utilities
South Dakota Gas
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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 $) PROPOSED	INCREASE AMOUNT
47	**Small Interruptible - Rate 71**									
48										
49		MIN BILLS	BILL			40.00	80.00			
50		MIN BILLS								
51		ALL	DekaTherms	42,146	42,146	0.48400	0.33000	20,399	13,908	(6,490)
52										
53	CUSTOMER CHARGE & MINNUM		BILL	151	151	40.00	80.00	6,040	12,080	6,040
54										
55	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
56		SUBTOTAL	DekaTherms	42,146	42,146			26,439	25,988	(450)
57										
58	Small Interruptible Rate Unbilled JUN 01									
59										
60		ALL THERMS	DekaTherms	0	0	0.48400	0.33000	0	0	0
61										
62										
63	CUSTOMER CHARGE & MINNUM		BILL	0	0	40.00	80.00	0	0	0
64										
65		SUB TOTAL	DekaTherms	145	145			915	1,135	220
66										
58	Small Interruptible - Rate 71 - Weather Normalization									
59										
60		MIN BILLS	BILL			40.00	80.00			
61		MIN BILLS								
62		ALL	DekaTherms	388	388	0.48400	0.33000	188	128	(60)
63										
64	CUSTOMER CHARGE & MINNUM		BILL	0	0	40.00	80.00	0	0	0
65										
66	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
67		SUBTOTAL	DekaTherms	388	388			188	128	(60)
68										
69	Small Interruptible Rate Unbilled JUN 02									
70										
71		ALL	DekaTherms	0	0	0.48400	0.33000	0	0	0
72										
73										
74		CUSTOMER CHARGE	BILL	0	0	40.00	80.00	0	0	0
75										
76		SUBTOTAL	DekaTherms	1,074	1,074			(555)	(910)	(354)
77										
78	Small Interruptible - Rate 71 - Reclassify as Rate 70									
79										
80		MIN BILLS	BILL			40.00	80.00			
81		MIN BILLS								
82		ALL	DekaTherms	(7,350)	(7,350)	0.48400	0.33000	(3,558)	(2,426)	1,132
83										
84	CUSTOMER CHARGE & MINNUM		BILL	(12)	(12)	40.00	80.00	(480)	(960)	(480)
85										
86	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
87		SUBTOTAL	DekaTherms	(7,350)	(7,350)			(4,038)	(3,386)	652
88										
89	**TOTAL - SMALL INTERRUPTIBLE - RATE 71**			**36,403**	**36,403**			**$ 22,948**	**$ 22,956**	**$ 8**

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LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE	TYPE OF CHARGE	UNIT	>-------- QUANTITY --------< PRESENT	PROPOSED	>-- RATE ($/UNIT) --< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>-- INCREASE -- AMOUNT
90										
91	**Large Interruptible - Rate 85**									
92										
93		MIN BILLS	BILL			150.00	150.00			
94		MIN BILLS								
95		ALL	DekaTherms	88,681	88,681	0.17700	0.17700	15,697	15,697	0
96										
97	CUSTOMER CHARGE & MINNUM		BILL	12	12	150.00	150.00	1,800	1,800	0
98										
99	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
100		SUBTOTAL	DekaTherms	88,681	88,681			17,497	17,497	0
101										
102	**TOTAL - LARGE INTERRUPTIBLE - RATE 85**			**88,681**	**88,681**			**$ 17,497**	**$ 17,497**	**$ -**
103										
104	**Small Interruptible Transportion - Rate 81**									
105										
106		MIN BILLS	BILL			90.00	90.00			
107		MIN BILLS								
108		ALL	DekaTherms	432,707	432,707	0.48400	0.33000	209,430	142,793	(66,637)
109										
110	CUSTOMER CHARGE & MINNUM		BILL	377	377	90.00	90.00	33,930	33,930	0
111										
112	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
113		SUBTOTAL	DekaTherms	432,707	432,707			243,360	176,723	(66,637)
114										
115	Small Interruptible Transportion - Rate 81 - Weather Normalization									
116										
117		MIN BILLS	BILL			90.00	90.00			
118		MIN BILLS								
119		ALL	DekaTherms	1,789	1,789	0.48400	0.33000	866	590	(275)
120										
121	CUSTOMER CHARGE & MINNUM		BILL	0	0	90.00	90.00	0	0	0
122										
123	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
124		SUBTOTAL	DekaTherms	1,789	1,789			866	590	(275)

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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 $) PROPOSED	INCREASE AMOUNT
125										
115	Small Interruptible Transportation - Rate 81 - Cut Out of Service									
116										
117		MIN BILLS	BILL			90.00	90.00			
118		MIN BILLS								
119		ALL	DekaTherms	(156)	(156)	0.48400	0.33000	(76)	(51)	24
120										
121	CUSTOMER CHARGE & MINNUM		BILL	(5)	(5)	90.00	90.00	(450)	(450)	0
122										
123	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
124		SUBTOTAL	DekaTherms	(156)	(156)			(526)	(501)	24
125										
126	Small Interruptible Transportation - Rate 81 - Reclassify as Rate 70									
127										
128		MIN BILLS	BILL			90.00	90.00			
129		MIN BILLS								
130		ALL	DekaTherms	(1,878)	(1,878)	0.48400	0.33000	(909)	(620)	289
131										
132	CUSTOMER CHARGE & MINNUM		BILL	(12)	(12)	90.00	90.00	(1,080)	(1,080)	0
133										
134	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
135		SUBTOTAL	DekaTherms	(1,878)	(1,878)			(1,989)	(1,700)	289
136										
126	**TOTAL - SMALL INTERRUPTIBLE TRANSPORTATION - RATE 81**			**432,462**	**432,462**			**241,711**	**175,112**	**$ (66,599)**
127										
128										
129	**Large Interruptible Transportation - Rate 82**									
130										
131		MIN BILLS	BILL			200.00	200.00			
132		MIN BILLS								
133		ALL	DekaTherms	862,122	862,122	0.17700	0.17700	152,596	152,596	0
134										
135	CUSTOMER CHARGE & MINNUM		BILL	175	175	200.00	200.00	35,000	35,000	0
136										
137	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
138		SUBTOTAL	DekaTherms	862,122	862,122			187,596	187,596	0
139										
140	Large Interruptible Transportation - Rate 82 - Cut Out of Service									
141										
142		MIN BILLS	BILL			200.00	200.00			
143		MIN BILLS								
144		ALL	DekaTherms	(91,693)	(91,693)	0.17700	0.17700	(16,230)	(16,230)	0
145										
146	CUSTOMER CHARGE & MINNUM		BILL	(8)	(8)	200.00	200.00	(1,600)	(1,600)	0
147										
148	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0
149		SUBTOTAL	DekaTherms	(91,693)	(91,693)			(17,830)	(17,830)	0
150										
140	**TOTAL - LARGE INTERRUPTIBLE TRANSPORTATION - RATE 82**			**770,429**	**770,429**			**$ 169,766**	**$ 169,766**	**$ -**
141										
142	**TOTAL - OTHER INTERRUPTIBLE and TRANSPORTATION**			**1,327,974**	**1,327,974**			**$ 451,922**	**$ 385,331**	**$ (66,591)**

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
1	CUSTOMER CHARGE	$7.00	$7.00
2	FIRST 10 DEKATHERMS	$1.39600	$1.39600
3	EXCESS DEKATHERMS	$0.89600	$0.89600
4	PGA	$3.70000	$3.70000

Rate 600 **SMALL METER RESIDENTIAL**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
5	0	$7.00	$7.00	$0.00	0.00%
6	1	12.10	12.10	0.00	0.00%
7	2	17.19	17.19	0.00	0.00%
8	3	22.29	22.29	0.00	0.00%
9	4	27.38	27.38	0.00	0.00%
10	5	32.48	32.48	0.00	0.00%
11	6	37.58	37.58	0.00	0.00%
12	7	42.67	42.67	0.00	0.00%
13	8	47.77	47.77	0.00	0.00%
14	9	52.86	52.86	0.00	0.00%
15	10	57.96	57.96	0.00	0.00%
16	12	67.15	67.15	0.00	0.00%
17	15	80.94	80.94	0.00	0.00%
18	20	103.92	103.92	0.00	0.00%
19	25	126.90	126.90	0.00	0.00%
20	30	149.88	149.88	0.00	0.00%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	ROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	15	$ 80.94	$ 80.94	$ -	0.0%
FEB	11	62.56	62.56	-	0.0%
MAR	11	62.56	62.56	-	0.0%
APR	7	42.67	42.67	-	0.0%
MAY	4	27.38	27.38	-	0.0%
JUN	3	22.29	22.29	-	0.0%
JUL	2	17.19	17.19	-	0.0%
AUG	2	17.19	17.19	-	0.0%
SEP	3	22.29	22.29	-	0.0%
OCT	6	37.58	37.58	-	0.0%
NOV	9	52.86	52.86	-	0.0%
DEC	13	71.75	71.75	-	0.0%
TOTAL	86	$517.26	$517.26	$0.00	0.0%

AVERAGE MONTHLY USE = 7.2 DekaTherms

Source:
Exhibit (MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
21	CUSTOMER CHARGE	$7.50	$7.50
22	FIRST 15 DEKATHERMS	$1.25500	$1.37300
23	EXCESS DEKATHERMS	$0.75600	$0.87400
24	PGA	$3.70000	$3.70000

Rate 700 **SMALL METER FIRM GENERAL SERVICE**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
25	0	7.50	7.50	$0.00	0.00%
26	5	32.28	32.87	0.59	1.83%
27	10	57.05	58.23	1.18	2.07%
28	15	81.83	83.60	1.77	2.16%
29	20	104.11	106.47	2.36	2.27%
30	30	148.67	152.21	3.54	2.38%
31	40	193.23	197.95	4.72	2.44%
32	50	237.79	243.69	5.90	2.48%
33	60	282.35	289.43	7.08	2.51%
34	70	326.91	335.17	8.26	2.53%
35	80	371.47	380.91	9.44	2.54%
36	90	416.03	426.65	10.62	2.55%
37	100	460.59	472.39	11.80	2.56%
38	150	683.39	701.09	17.70	2.59%
39	200	906.19	929.79	23.60	2.60%
40	250	1,128.99	1,158.49	29.50	2.61%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	ROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	51	$ 242.24	$ 248.26	$ 6.02	2.5%
FEB	39	188.77	193.37	4.60	2.4%
MAR	39	188.77	193.37	4.60	2.4%
APR	24	121.93	124.76	2.83	2.3%
MAY	15	81.83	83.60	1.77	2.2%
JUN	9	52.10	53.16	1.06	2.0%
JUL	6	37.23	37.94	0.71	1.9%
AUG	6	37.23	37.94	0.71	1.9%
SEP	12	66.96	68.38	1.42	2.1%
OCT	21	108.56	111.04	2.48	2.3%
NOV	33	162.03	165.93	3.89	2.4%
DEC	45	215.51	220.82	5.31	2.5%
TOTAL	300	$1,503.15	$1,538.55	$35.40	2.4%

41 AVERAGE MONTHLY USE = 25 DekaTherms

Source:
Exhibit (MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
42	CUSTOMER CHARGE	$14.00	$14.00
43	FIRST 10 DEKATHERMS	$1.39600	$1.39600
44	EXCESS DEKATHERMS	$0.89600	$0.89600
45	PGA	$3.70000	$3.70000

Rate 601 **LARGE METER RESIDENTIAL**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
46	0	14.00	14.00	$0.00	0.00%
47	5	39.48	39.48	0.00	0.00%
48	10	64.96	64.96	0.00	0.00%
49	15	87.94	87.94	0.00	0.00%
50	20	110.92	110.92	0.00	0.00%
51	30	156.88	156.88	0.00	0.00%
52	40	202.84	202.84	0.00	0.00%
53	50	248.80	248.80	0.00	0.00%
54	60	294.76	294.76	0.00	0.00%
55	70	340.72	340.72	0.00	0.00%
56	80	386.68	386.68	0.00	0.00%
57	90	432.64	432.64	0.00	0.00%
58	100	478.60	478.60	0.00	0.00%
59	150	708.40	708.40	0.00	0.00%
60	200	938.20	938.20	0.00	0.00%
61	250	1,168.00	1,168.00	0.00	0.00%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	ROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	82	$ 395.87	$ 395.87	-	0.0%
FEB	63	308.55	308.55	-	0.0%
MAR	63	308.55	308.55	-	0.0%
APR	39	198.24	198.24	-	0.0%
MAY	24	129.30	129.30	-	0.0%
JUN	15	87.94	87.94	-	0.0%
JUL	10	64.96	64.96	-	0.0%
AUG	10	64.96	64.96	-	0.0%
SEP	19	106.32	106.32	-	0.0%
OCT	34	175.26	175.26	-	0.0%
NOV	53	262.59	262.59	-	0.0%
DEC	73	354.51	354.51	-	0.0%
TOTAL	485	$2,457.06	$2,457.06	$0.00	0.0%

62 AVERAGE MONTHLY USE = 40.4 DekaTherms

Source:
Exhibit (MCB-5)

Montana-Dakota Utilities
South Dakota - Gas
Residential and Firm Commercial
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
63	CUSTOMER CHARGE	$15.00	$15.00
64	FIRST 15 DEKATHERMS	$1.25500	$1.37300
65	EXCESS DEKATHERMS	$0.75600	$0.87400
66	PGA	$3.70000	$3.70000

Rate 701 **LARGE METER FIRM GENERAL SERVICE**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
67	0	15.00	15.00	$0.00	0.00%
68	5	39.78	40.37	0.59	1.48%
69	10	64.55	65.73	1.18	1.83%
70	15	89.33	91.10	1.77	1.98%
71	20	111.61	113.97	2.36	2.11%
72	30	156.17	159.71	3.54	2.27%
73	40	200.73	205.45	4.72	2.35%
74	50	245.29	251.19	5.90	2.41%
75	60	289.85	296.93	7.08	2.44%
76	70	334.41	342.67	8.26	2.47%
77	80	378.97	388.41	9.44	2.49%
78	90	423.53	434.15	10.62	2.51%
79	100	468.09	479.89	11.80	2.52%
80	150	690.89	708.59	17.70	2.56%
81	200	913.69	937.29	23.60	2.58%
82	250	1,136.49	1,165.99	29.50	2.60%
83	300	1,359.29	1,394.69	35.40	2.60%
84	350	1,582.09	1,623.39	41.30	2.61%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	ROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	207	$ 944.88	$ 969.30	24.43	2.6%
FEB	159	730.99	749.75	18.76	2.6%
MAR	159	730.99	749.75	18.76	2.6%
APR	98	459.17	470.74	11.56	2.5%
MAY	61	294.30	301.50	7.20	2.4%
JUN	37	187.36	191.72	4.37	2.3%
JUL	25	133.89	136.84	2.95	2.2%
AUG	25	133.89	136.84	2.95	2.2%
SEP	49	240.83	246.61	5.78	2.4%
OCT	86	405.70	415.85	10.15	2.5%
NOV	135	624.05	639.98	15.93	2.6%
DEC	184	842.39	864.10	21.71	2.6%
TOTAL	1,225	$5,728.42	$5,872.97	$144.55	2.5%

85 AVERAGE MONTHLY USE = 102.1 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	PROPOSED	>-- RATE ($/UNIT) --< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>-- INCREASE --< AMOUNT	PERCENT
	Firm Contract Service - Rate 702										
1		MIN BILLS	BILL			150.00	150.00				
2											
3		ALL	DekaTherms	625,741	625,741	0.34800	0.34800	217,758	217,758	0	
4											
5		CUSTOMER CHARGE & MINNUM	BILL	12	12	150.00	150.00	1,800	1,800	0	
6											
7		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			5.24100	5.24100	3,279,509	3,279,509	0	
8	**TOTAL - Firm Contract Service - Rate 702**			**625,741**	**625,741**			**$ 3,499,066**	**$ 3,499,066**	**$ -**	**0.0%**
9											
10	**Ellsworth Air Force Base**										
11											
12		MIN BILLS	BILL			95.00	95.00				
13											
14		ALL	DekaTherms	577,549	577,549	0.06200	0.06200	35,808	35,808	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	2,285,363	2,285,363	0	
19	**TOTAL - Ellsworth Air Force Base**			**577,549**	**577,549**			**$ 2,322,311**	**$ 2,322,311**	**$ -**	**0.0%**
20											
21	**Small Interruptible - Rate 71**										
22											
23		MIN BILLS	BILL			40.00	80.00				
24											
25		ALL	DekaTherms	36,403	36,403	0.48400	0.33000	17,619	12,013	(5,606)	
26											
27		CUSTOMER CHARGE & MINNUM	BILL	139	139	40.00	80.00	5,560	11,120	5,560	
28											
29		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			5.24100	5.24100	190,786	190,786	0	
30	**TOTAL - SMALL INTERRUPTIBLE - RATE 71**			**36,403**	**36,403**			**$ 213,964**	**$ 213,918**	**$ (46)**	**0.0%**
31											

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	PROPOSED	>-- RATE ($/UNIT) --< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>-- INCREASE ---< AMOUNT	PERCENT
32	**Large Interruptible - Rate 85**										
33											
34		MIN BILLS	BILL			150.00	150.00				
35											
36		ALL	DekaTherms	88,681	88,681	0.17700	0.17700	15,697	15,697	0	
37											
38		CUSTOMER CHARGE & MINNUM	BILL	12	12	150.00	150.00	1,800	1,800	0	
39											
40		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			4.00200	4.00200	354,901	354,901	0	
41	**TOTAL - LARGE INTERRUPTIBLE - RATE 85**			**88,681**	**88,681**			**$ 372,398**	**$ 372,398**	**$ -**	**0.0%**
42											
43	**Small Interruptible Transportion - Rate 81**										
44											
45		MIN BILLS	BILL			90.00	90.00				
46											
47		ALL	DekaTherms	432,462	432,462	0.48400	0.33000	209,311	142,712	(66,599)	
48											
49		CUSTOMER CHARGE & MINNUM	BILL	360	360	90.00	90.00	32,400	32,400	0	
50											
51		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			5.24100	5.24100	2,266,532	2,266,532	0	
52	**TOTAL - SMALL INTERRUPTIBLE TRANSPORTATION - RATE 81**			**432,462**	**432,462**			**$ 2,508,243**	**$ 2,441,644**	**$ (66,599)**	**-2.7%**
53											
54											
55	**Large Interruptible Transportation - Rate 82**										
56											
57		MIN BILLS	BILL			200.00	200.00				
58											
59		ALL	DekaTherms	770,429	770,429	0.17700	0.17700	136,366	136,366	0	
60											
61		CUSTOMER CHARGE & MINNUM	BILL	167	167	200.00	200.00	33,400	33,400	0	
62											
63		PURCHASED GAS ADJUSTMENT	Effective 1/1/2003			4.00200	4.00200	3,083,257	3,083,257	0	
64	**TOTAL - LARGE INTERRUPTIBLE TRANSPORTATION - RATE 82**			**770,429**	**770,429**			**$ 3,253,023**	**$ 3,253,023**	**$ -**	**0.0%**
65											
66	**TOTAL - OTHER INTERRUPTIBLE and TRANSPORTATION**			**1,327,974**	**1,327,974**			**$ 6,347,629**	**$ 6,280,983**	**$ (66,645)**	**-1.0%**

Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending June 30, 2002

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
(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Jul 01	1	05/29/01	06/28/01	29-May-01	27-Jun-01	30	144	103
Jul 01	2	06/01/01	07/02/01	01-Jun-01	01-Jul-01	31	136	89
Jul 01	3	06/04/01	07/03/01	04-Jun-01	02-Jul-01	29	105	72
Jul 01	4	06/05/01	07/05/01	05-Jun-01	04-Jul-01	30	89	69
Jul 01	5	06/06/01	07/06/01	06-Jun-01	05-Jul-01	30	79	65
Jul 01	6	06/07/01	07/09/01	07-Jun-01	08-Jul-01	32	73	63
Jul 01	7	06/08/01	07/10/01	08-Jun-01	09-Jul-01	32	68	60
Jul 01	8	06/11/01	07/11/01	11-Jun-01	10-Jul-01	30	66	49
Jul 01	9	06/12/01	07/12/01	12-Jun-01	11-Jul-01	30	65	47
Jul 01	10	06/13/01	07/13/01	13-Jun-01	12-Jul-01	30	61	45
Jul 01	11	06/14/01	07/16/01	14-Jun-01	15-Jul-01	32	58	45
Jul 01	12	06/15/01	07/17/01	15-Jun-01	16-Jul-01	32	45	44
Jul 01	13	06/18/01	07/18/01	18-Jun-01	17-Jul-01	30	32	38
Jul 01	14	06/19/01	07/19/01	19-Jun-01	18-Jul-01	30	28	36
Jul 01	15	06/20/01	07/20/01	20-Jun-01	19-Jul-01	30	20	34
Jul 01	16	06/21/01	07/23/01	21-Jun-01	22-Jul-01	32	13	32
Jul 01	17	06/22/01	07/24/01	22-Jun-01	23-Jul-01	32	9	30
Jul 01	18	06/25/01	07/25/01	25-Jun-01	24-Jul-01	30	9	24
Jul 01	19	06/26/01	07/26/01	26-Jun-01	25-Jul-01	30	9	22
Jul 01	20	06/27/01	07/27/01	27-Jun-01	26-Jul-01	30	9	20
Jul 01 Average							**55.9**	**49.4**
Aug 01	1	06/28/01	07/30/01	28-Jun-01	29-Jul-01	32	9	19
Aug 01	2	07/02/01	08/01/01	02-Jul-01	31-Jul-01	30	0	15
Aug 01	3	07/03/01	08/02/01	03-Jul-01	01-Aug-01	30	0	14
Aug 01	4	07/05/01	08/03/01	05-Jul-01	02-Aug-01	29	0	12
Aug 01	5	07/06/01	08/06/01	06-Jul-01	05-Aug-01	31	0	11
Aug 01	6	07/09/01	08/07/01	09-Jul-01	06-Aug-01	29	0	8
Aug 01	7	07/10/01	08/08/01	10-Jul-01	07-Aug-01	29	0	7
Aug 01	8	07/11/01	08/09/01	11-Jul-01	08-Aug-01	29	0	6
Aug 01	9	07/12/01	08/10/01	12-Jul-01	09-Aug-01	29	0	5
Aug 01	10	07/13/01	08/13/01	13-Jul-01	12-Aug-01	31	0	4
Aug 01	11	07/16/01	08/14/01	16-Jul-01	13-Aug-01	29	0	1
Aug 01	12	07/17/01	08/15/01	17-Jul-01	14-Aug-01	29	0	0
Aug 01	13	07/18/01	08/16/01	18-Jul-01	15-Aug-01	29	0	0
Aug 01	14	07/19/01	08/17/01	19-Jul-01	16-Aug-01	29	0	0
Aug 01	15	07/20/01	08/20/01	20-Jul-01	19-Aug-01	31	0	3
Aug 01	16	07/23/01	08/21/01	23-Jul-01	20-Aug-01	29	0	4
Aug 01	17	07/24/01	08/22/01	24-Jul-01	21-Aug-01	29	0	5
Aug 01	18	07/25/01	08/23/01	25-Jul-01	22-Aug-01	29	0	6
Aug 01	19	07/26/01	08/24/01	26-Jul-01	23-Aug-01	29	0	7
Aug 01	20	07/27/01	08/27/01	27-Jul-01	26-Aug-01	31	0	11
Aug 01 Average							**0.5**	**6.9**

Sources:
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Column (I): Actual Number of HDDs in Billing Period
Column (J): Normal Number of HDDs in Billing Period

Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending June 30, 2002

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
(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Sep 01	1	07/30/01	08/28/01	30-Jul-01	27-Aug-01	29	0	13
Sep 01	2	08/01/01	09/04/01	01-Aug-01	03-Sep-01	34	0	30
Sep 01	3	08/02/01	09/05/01	02-Aug-01	04-Sep-01	34	0	33
Sep 01	4	08/03/01	09/06/01	03-Aug-01	05-Sep-01	34	0	36
Sep 01	5	08/06/01	09/07/01	06-Aug-01	06-Sep-01	32	0	40
Sep 01	6	08/07/01	09/10/01	07-Aug-01	09-Sep-01	34	32	53
Sep 01	7	08/08/01	09/11/01	08-Aug-01	10-Sep-01	34	36	58
Sep 01	8	08/09/01	09/12/01	09-Aug-01	11-Sep-01	34	36	63
Sep 01	9	08/10/01	09/13/01	10-Aug-01	12-Sep-01	34	39	68
Sep 01	10	08/13/01	09/14/01	13-Aug-01	13-Sep-01	32	50	73
Sep 01	11	08/14/01	09/17/01	14-Aug-01	16-Sep-01	34	75	91
Sep 01	12	08/15/01	09/18/01	15-Aug-01	17-Sep-01	34	85	98
Sep 01	13	08/16/01	09/19/01	16-Aug-01	18-Sep-01	34	89	105
Sep 01	14	08/17/01	09/20/01	17-Aug-01	19-Sep-01	34	89	112
Sep 01	15	08/20/01	09/21/01	20-Aug-01	20-Sep-01	32	96	116
Sep 01	16	08/21/01	09/24/01	21-Aug-01	23-Sep-01	34	121	139
Sep 01	17	08/22/01	09/25/01	22-Aug-01	24-Sep-01	34	129	147
Sep 01	18	08/23/01	09/26/01	23-Aug-01	25-Sep-01	34	134	155
Sep 01	19	08/24/01	09/27/01	24-Aug-01	26-Sep-01	34	135	164
Sep 01	20	08/27/01	09/28/01	27-Aug-01	27-Sep-01	32	135	170
Sep 01 Average							**64.1**	**88.2**
Oct 01	1	08/28/01	10/01/01	28-Aug-01	30-Sep-01	34	138	219
Oct 01	2	09/04/01	10/01/01	04-Sep-01	30-Sep-01	27	138	202
Oct 01	3	09/05/01	10/02/01	05-Sep-01	01-Oct-01	27	138	188
Oct 01	4	09/06/01	10/03/01	06-Sep-01	02-Oct-01	27	143	196
Oct 01	5	09/07/01	10/04/01	07-Sep-01	03-Oct-01	27	156	203
Oct 01	6	09/10/01	10/05/01	10-Sep-01	04-Oct-01	25	146	201
Oct 01	7	09/11/01	10/08/01	11-Sep-01	07-Oct-01	27	199	233
Oct 01	8	09/12/01	10/09/01	12-Sep-01	08-Oct-01	27	204	241
Oct 01	9	09/13/01	10/10/01	13-Sep-01	09-Oct-01	27	216	249
Oct 01	10	09/14/01	10/11/01	14-Sep-01	10-Oct-01	27	225	258
Oct 01	11	09/17/01	10/12/01	17-Sep-01	11-Oct-01	25	221	254
Oct 01	12	09/18/01	10/15/01	18-Sep-01	14-Oct-01	27	270	293
Oct 01	13	09/19/01	10/16/01	19-Sep-01	15-Oct-01	27	294	302
Oct 01	14	09/20/01	10/17/01	20-Sep-01	16-Oct-01	27	318	312
Oct 01	15	09/21/01	10/18/01	21-Sep-01	17-Oct-01	27	318	322
Oct 01	16	09/24/01	10/19/01	24-Sep-01	18-Oct-01	25	316	316
Oct 01	17	09/25/01	10/22/01	25-Sep-01	21-Oct-01	27	357	343
Oct 01	18	09/26/01	10/23/01	26-Sep-01	22-Oct-01	27	365	372
Oct 01	19	09/27/01	10/24/01	27-Sep-01	23-Oct-01	27	377	382
Oct 01	20	09/28/01	10/25/01	28-Sep-01	24-Oct-01	27	403	392
Oct 01 Average							**247.1**	**273.9**

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Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending June 30, 2002

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
(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Nov 01	1	10/01/01	10/26/01	01-Oct-01	25-Oct-01	25	429	383
Nov 01	2	10/01/01	11/01/01	01-Oct-01	31-Oct-01	31	523	521
Nov 01	3	10/02/01	11/02/01	02-Oct-01	01-Nov-01	31	543	536
Nov 01	4	10/03/01	11/05/01	03-Oct-01	04-Nov-01	33	580	602
Nov 01	5	10/04/01	11/06/01	04-Oct-01	05-Nov-01	33	579	618
Nov 01	6	10/05/01	11/07/01	05-Oct-01	06-Nov-01	33	571	634
Nov 01	7	10/08/01	11/08/01	08-Oct-01	07-Nov-01	31	537	625
Nov 01	8	10/09/01	11/09/01	09-Oct-01	08-Nov-01	31	556	640
Nov 01	9	10/10/01	11/12/01	10-Oct-01	11-Nov-01	33	593	714
Nov 01	10	10/11/01	11/13/01	11-Oct-01	12-Nov-01	33	589	730
Nov 01	11	10/12/01	11/14/01	12-Oct-01	13-Nov-01	33	583	746
Nov 01	12	10/15/01	11/15/01	15-Oct-01	14-Nov-01	31	536	731
Nov 01	13	10/16/01	11/16/01	16-Oct-01	15-Nov-01	31	523	746
Nov 01	14	10/17/01	11/19/01	17-Oct-01	18-Nov-01	33	561	825
Nov 01	15	10/18/01	11/20/01	18-Oct-01	19-Nov-01	33	592	841
Nov 01	16	10/19/01	11/21/01	19-Oct-01	20-Nov-01	33	590	856
Nov 01	17	10/22/01	11/23/01	22-Oct-01	22-Nov-01	32	588	868
Nov 01	18	10/23/01	11/26/01	23-Oct-01	25-Nov-01	34	661	953
Nov 01	19	10/24/01	11/27/01	24-Oct-01	26-Nov-01	34	696	968
Nov 01	20	10/25/01	11/28/01	25-Oct-01	27-Nov-01	34	729	984
Nov 01 Average							**578.0**	**726.1**
Dec 01	1	10/26/01	11/29/01	26-Oct-01	28-Nov-01	34	761	999
Dec 01	2	11/01/01	12/03/01	01-Nov-01	02-Dec-01	32	808	1008
Dec 01	3	11/02/01	12/04/01	02-Nov-01	03-Dec-01	32	808	1020
Dec 01	4	11/05/01	12/05/01	05-Nov-01	04-Dec-01	30	796	980
Dec 01	5	11/06/01	12/06/01	06-Nov-01	05-Dec-01	30	814	990
Dec 01	6	11/07/01	12/07/01	07-Nov-01	06-Dec-01	30	832	1001
Dec 01	7	11/08/01	12/10/01	08-Nov-01	09-Dec-01	32	894	1087
Dec 01	8	11/09/01	12/11/01	09-Nov-01	10-Dec-01	32	906	1098
Dec 01	9	11/12/01	12/12/01	12-Nov-01	11-Dec-01	30	893	1050
Dec 01	10	11/13/01	12/13/01	13-Nov-01	12-Dec-01	30	918	1059
Dec 01	11	11/14/01	12/14/01	14-Nov-01	13-Dec-01	30	939	1068
Dec 01	12	11/15/01	12/17/01	15-Nov-01	16-Dec-01	32	1027	1157
Dec 01	13	11/16/01	12/18/01	16-Nov-01	17-Dec-01	32	1037	1166
Dec 01	14	11/19/01	12/19/01	19-Nov-01	18-Dec-01	30	1012	1110
Dec 01	15	11/20/01	12/20/01	20-Nov-01	19-Dec-01	30	1009	1118
Dec 01	16	11/21/01	12/21/01	21-Nov-01	20-Dec-01	30	1022	1126
Dec 01	17	11/23/01	12/24/01	23-Nov-01	23-Dec-01	31	1093	1182
Dec 01	18	11/26/01	12/26/01	26-Nov-01	25-Dec-01	30	1088	1160
Dec 01	19	11/27/01	12/27/01	27-Nov-01	26-Dec-01	30	1069	1167
Dec 01	20	11/28/01	12/28/01	28-Nov-01	27-Dec-01	30	1045	1173
Dec 01 Average							**938.6**	**1086.0**

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Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending June 30, 2002

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
(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Jan 02	1	11/29/01	12/31/01	29-Nov-01	30-Dec-01	32	1134	1263
Jan 02	2	12/03/01	01/02/02	03-Dec-01	01-Jan-02	30	1106	1202
Jan 02	3	12/04/01	01/03/02	04-Dec-01	02-Jan-02	30	1134	1208
Jan 02	4	12/05/01	01/04/02	05-Dec-01	03-Jan-02	30	1136	1214
Jan 02	5	12/06/01	01/07/02	06-Dec-01	06-Jan-02	32	1197	1306
Jan 02	6	12/07/01	01/08/02	07-Dec-01	07-Jan-02	32	1187	1311
Jan 02	7	12/10/01	01/09/02	10-Dec-01	08-Jan-02	30	1116	1240
Jan 02	8	12/11/01	01/10/02	11-Dec-01	09-Jan-02	30	1103	1244
Jan 02	9	12/12/01	01/11/02	12-Dec-01	10-Jan-02	30	1096	1248
Jan 02	10	12/13/01	01/14/02	13-Dec-01	13-Jan-02	32	1148	1338
Jan 02	11	12/14/01	01/15/02	14-Dec-01	14-Jan-02	32	1154	1342
Jan 02	12	12/17/01	01/16/02	17-Dec-01	15-Jan-02	30	1107	1265
Jan 02	13	12/18/01	01/17/02	18-Dec-01	16-Jan-02	30	1131	1268
Jan 02	14	12/19/01	01/18/02	19-Dec-01	17-Jan-02	30	1144	1271
Jan 02	15	12/20/01	01/21/02	20-Dec-01	20-Jan-02	32	1237	1356
Jan 02	16	12/21/01	01/22/02	21-Dec-01	21-Jan-02	32	1230	1357
Jan 02	17	12/24/01	01/23/02	24-Dec-01	22-Jan-02	30	1141	1276
Jan 02	18	12/26/01	01/24/02	26-Dec-01	23-Jan-02	29	1100	1236
Jan 02	19	12/27/01	01/25/02	27-Dec-01	24-Jan-02	29	1106	1236
Jan 02	20	12/28/01	01/28/02	28-Dec-01	27-Jan-02	31	1147	1319
Jan 02 Average							**1,142.7**	**1,275.0**
Feb 02	1	12/31/01	01/29/02	31-Dec-01	28-Jan-02	29	1053	1234
Feb 02	2	01/02/02	02/01/02	02-Jan-02	31-Jan-02	30	1091	1271
Feb 02	3	01/03/02	02/04/02	03-Jan-02	03-Feb-02	32	1148	1350
Feb 02	4	01/04/02	02/05/02	04-Jan-02	04-Feb-02	32	1154	1347
Feb 02	5	01/07/02	02/06/02	07-Jan-02	05-Feb-02	30	1096	1258
Feb 02	6	01/08/02	02/07/02	08-Jan-02	06-Feb-02	30	1102	1255
Feb 02	7	01/09/02	02/08/02	09-Jan-02	07-Feb-02	30	1110	1252
Feb 02	8	01/10/02	02/11/02	10-Jan-02	10-Feb-02	32	1197	1326
Feb 02	9	01/11/02	02/12/02	11-Jan-02	11-Feb-02	32	1188	1322
Feb 02	10	01/14/02	02/13/02	14-Jan-02	12-Feb-02	30	1132	1232
Feb 02	11	01/15/02	02/14/02	15-Jan-02	13-Feb-02	30	1119	1227
Feb 02	12	01/16/02	02/15/02	16-Jan-02	14-Feb-02	30	1096	1222
Feb 02	13	01/17/02	02/18/02	17-Jan-02	17-Feb-02	32	1122	1292
Feb 02	14	01/18/02	02/19/02	18-Jan-02	18-Feb-02	32	1099	1286
Feb 02	15	01/21/02	02/20/02	21-Jan-02	19-Feb-02	30	1003	1197
Feb 02	16	01/22/02	02/21/02	22-Jan-02	20-Feb-02	30	1008	1192
Feb 02	17	01/23/02	02/22/02	23-Jan-02	21-Feb-02	30	1006	1186
Feb 02	18	01/24/02	02/25/02	24-Jan-02	24-Feb-02	32	1058	1252
Feb 02	19	01/25/02	02/26/02	25-Jan-02	25-Feb-02	32	1082	1245
Feb 02	20	01/28/02	02/27/02	28-Jan-02	26-Feb-02	30	1061	1155
Feb 02 Average							**1,096.3**	**1,255.1**

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Montana-Dakota Utilities
South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending June 30, 2002

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
(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Mar 02	1	01/29/02	02/28/02	29-Jan-02	27-Feb-02	30	1054	1149
Mar 02	2	02/01/02	03/01/02	01-Feb-02	28-Feb-02	28	954	1061
Mar 02	3	02/04/02	03/04/02	04-Feb-02	03-Mar-02	28	1022	1042
Mar 02	4	02/05/02	03/05/02	05-Feb-02	04-Mar-02	28	1012	1036
Mar 02	5	02/06/02	03/06/02	06-Feb-02	05-Mar-02	28	1004	1029
Mar 02	6	02/07/02	03/07/02	07-Feb-02	06-Mar-02	28	1022	1022
Mar 02	7	02/08/02	03/08/02	08-Feb-02	07-Mar-02	28	1048	1014
Mar 02	8	02/11/02	03/11/02	11-Feb-02	10-Mar-02	28	1099	993
Mar 02	9	02/12/02	03/12/02	12-Feb-02	11-Mar-02	28	1104	985
Mar 02	10	02/13/02	03/13/02	13-Feb-02	12-Mar-02	28	1080	977
Mar 02	11	02/14/02	03/14/02	14-Feb-02	13-Mar-02	28	1084	970
Mar 02	12	02/15/02	03/15/02	15-Feb-02	14-Mar-02	28	1100	962
Mar 02	13	02/18/02	03/18/02	18-Feb-02	17-Mar-02	28	1155	938
Mar 02	14	02/19/02	03/19/02	19-Feb-02	18-Mar-02	28	1171	930
Mar 02	15	02/20/02	03/20/02	20-Feb-02	19-Mar-02	28	1182	922
Mar 02	16	02/21/02	03/21/02	21-Feb-02	20-Mar-02	28	1200	914
Mar 02	17	02/22/02	03/22/02	22-Feb-02	21-Mar-02	28	1234	906
Mar 02	18	02/25/02	03/25/02	25-Feb-02	24-Mar-02	28	1287	881
Mar 02	19	02/26/02	03/26/02	26-Feb-02	25-Mar-02	28	1277	873
Mar 02	20	02/27/02	03/27/02	27-Feb-02	26-Mar-02	28	1269	865
Mar 02 Average							**1,117.9**	**973.5**
Apr 02	1	02/28/02	03/28/02	28-Feb-02	27-Mar-02	28	1251	857
Apr 02	2	03/01/02	04/01/02	01-Mar-02	31-Mar-02	31	1313	925
Apr 02	3	03/04/02	04/02/02	04-Mar-02	01-Apr-02	29	1166	847
Apr 02	4	03/05/02	04/03/02	05-Mar-02	02-Apr-02	29	1185	837
Apr 02	5	03/06/02	04/04/02	06-Mar-02	03-Apr-02	29	1205	828
Apr 02	6	03/07/02	04/05/02	07-Mar-02	04-Apr-02	29	1193	819
Apr 02	7	03/08/02	04/08/02	08-Mar-02	07-Apr-02	31	1195	856
Apr 02	8	03/11/02	04/09/02	11-Mar-02	08-Apr-02	29	1060	782
Apr 02	9	03/12/02	04/10/02	12-Mar-02	09-Apr-02	29	1045	773
Apr 02	10	03/13/02	04/11/02	13-Mar-02	10-Apr-02	29	1047	764
Apr 02	11	03/14/02	04/12/02	14-Mar-02	11-Apr-02	29	1030	754
Apr 02	12	03/15/02	04/15/02	15-Mar-02	14-Apr-02	31	1002	786
Apr 02	13	03/18/02	04/16/02	18-Mar-02	15-Apr-02	29	880	717
Apr 02	14	03/19/02	04/17/02	19-Mar-02	16-Apr-02	29	858	708
Apr 02	15	03/20/02	04/18/02	20-Mar-02	17-Apr-02	29	829	698
Apr 02	16	03/21/02	04/19/02	21-Mar-02	18-Apr-02	29	800	688
Apr 02	17	03/22/02	04/22/02	22-Mar-02	21-Apr-02	31	826	715
Apr 02	18	03/25/02	04/23/02	25-Mar-02	22-Apr-02	29	699	650
Apr 02	19	03/26/02	04/24/02	26-Mar-02	23-Apr-02	29	659	640
Apr 02	20	03/27/02	04/25/02	27-Mar-02	24-Apr-02	29	636	630
Apr 02 Average							**994.0**	**763.7**

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South Dakota - Gas
Daily Temperature and Billing Cycle Data
Rapid City APO
Test Year Ending June 30, 2002

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
(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
May 02	1	03/28/02	04/26/02	28-Mar-02	25-Apr-02	29	633	620
May 02	2	04/01/02	05/01/02	01-Apr-02	30-Apr-02	30	614	595
May 02	3	04/02/02	05/02/02	02-Apr-02	01-May-02	30	617	585
May 02	4	04/03/02	05/03/02	03-Apr-02	02-May-02	30	588	576
May 02	5	04/04/02	05/06/02	04-Apr-02	05-May-02	32	584	595
May 02	6	04/05/02	05/07/02	05-Apr-02	06-May-02	32	571	585
May 02	7	04/08/02	05/08/02	08-Apr-02	07-May-02	30	551	529
May 02	8	04/09/02	05/09/02	09-Apr-02	08-May-02	30	547	520
May 02	9	04/10/02	05/10/02	10-Apr-02	09-May-02	30	559	511
May 02	10	04/11/02	05/13/02	11-Apr-02	12-May-02	32	600	524
May 02	11	04/12/02	05/14/02	12-Apr-02	13-May-02	32	595	514
May 02	12	04/15/02	05/15/02	15-Apr-02	14-May-02	30	580	463
May 02	13	04/16/02	05/16/02	16-Apr-02	15-May-02	30	577	453
May 02	14	04/17/02	05/17/02	17-Apr-02	16-May-02	30	573	443
May 02	15	04/18/02	05/20/02	18-Apr-02	19-May-02	32	604	451
May 02	16	04/19/02	05/21/02	19-Apr-02	20-May-02	32	594	440
May 02	17	04/22/02	05/22/02	22-Apr-02	21-May-02	30	507	393
May 02	18	04/23/02	05/23/02	23-Apr-02	22-May-02	30	502	383
May 02	19	04/24/02	05/24/02	24-Apr-02	23-May-02	30	522	373
May 02	20	04/25/02	05/28/02	25-Apr-02	27-May-02	33	539	384
May 02 Average							**572.9**	**496.9**
Jun 02	1	04/26/02	05/29/02	26-Apr-02	28-May-02	33	511	373
Jun 02	2	05/01/02	06/03/02	01-May-02	02-Jun-02	33	422	325
Jun 02	3	05/02/02	06/04/02	02-May-02	03-Jun-02	33	399	316
Jun 02	4	05/03/02	06/05/02	03-May-02	04-Jun-02	33	388	306
Jun 02	5	05/06/02	06/06/02	06-May-02	05-Jun-02	31	351	268
Jun 02	6	05/07/02	06/07/02	07-May-02	06-Jun-02	31	330	259
Jun 02	7	05/08/02	06/10/02	08-May-02	09-Jun-02	33	300	258
Jun 02	8	05/09/02	06/11/02	09-May-02	10-Jun-02	33	278	249
Jun 02	9	05/10/02	06/12/02	10-May-02	11-Jun-02	33	259	239
Jun 02	10	05/13/02	06/13/02	13-May-02	12-Jun-02	31	208	207
Jun 02	11	05/14/02	06/14/02	14-May-02	13-Jun-02	31	202	199
Jun 02	12	05/15/02	06/17/02	15-May-02	16-Jun-02	33	202	194
Jun 02	13	05/16/02	06/18/02	16-May-02	17-Jun-02	33	197	186
Jun 02	14	05/17/02	06/19/02	17-May-02	18-Jun-02	33	180	178
Jun 02	15	05/20/02	06/20/02	20-May-02	19-Jun-02	31	136	153
Jun 02	16	05/21/02	06/21/02	21-May-02	20-Jun-02	31	127	147
Jun 02	17	05/22/02	06/24/02	22-May-02	23-Jun-02	33	127	145
Jun 02	18	05/23/02	06/25/02	23-May-02	24-Jun-02	33	114	139
Jun 02	19	05/24/02	06/26/02	24-May-02	25-Jun-02	33	85	134
Jun 02	20	05/28/02	06/27/02	28-May-02	26-Jun-02	30	44	108
Jun 02 Average							**243.0**	**219.2**

Sources:
Columns (A) through (H): Provided by Montana-Dakota Utilities
Column (I): Actual Number of HDDs in Billing Period
Column (J): Normal Number of HDDs in Billing Period

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Temperature Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
01-May-01	67	46	57	8
02-May-01	61	31	46	19
03-May-01	56	43	50	15
04-May-01	59	34	47	18
05-May-01	49	35	42	23
06-May-01	58	32	45	20
07-May-01	66	31	49	16
08-May-01	76	40	58	7
09-May-01	75	49	62	3
10-May-01	66	45	56	9
11-May-01	67	41	54	11
12-May-01	82	43	63	2
13-May-01	92	49	71	0
14-May-01	84	54	69	0
15-May-01	73	53	63	2
16-May-01	81	47	64	1
17-May-01	67	45	56	9
18-May-01	83	43	63	2
19-May-01	77	51	64	1
20-May-01	59	41	50	15
21-May-01	61	38	50	15
22-May-01	67	36	52	13
23-May-01	65	36	51	14
24-May-01	58	38	48	17
25-May-01	65	40	53	12
26-May-01	77	38	58	7
27-May-01	80	51	66	0
28-May-01	77	48	63	2
29-May-01	63	54	59	6
30-May-01	67	49	58	7
31-May-01	75	47	61	4
01-Jun-01	71	37	54	11
02-Jun-01	73	36	55	10
03-Jun-01	57	52	55	10
04-Jun-01	52	45	49	16
05-Jun-01	73	36	55	10
06-Jun-01	72	46	59	6
07-Jun-01	72	47	60	5
08-Jun-01	77	49	63	2
09-Jun-01	85	54	70	0
10-Jun-01	83	58	71	0
11-Jun-01	74	54	64	1
12-Jun-01	69	52	61	4
13-Jun-01	70	54	62	3
14-Jun-01	60	43	52	13
15-Jun-01	73	41	57	8

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Temperature Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
16-Jun-01	77	43	60	5
17-Jun-01	78	51	65	0
18-Jun-01	71	50	61	4
19-Jun-01	67	46	57	8
20-Jun-01	66	50	58	7
21-Jun-01	76	45	61	4
22-Jun-01	84	49	67	0
23-Jun-01	99	56	78	0
24-Jun-01	100	65	83	0
25-Jun-01	95	61	78	0
26-Jun-01	81	65	73	0
27-Jun-01	94	60	77	0
28-Jun-01	92	61	77	0
29-Jun-01	90	62	76	0
30-Jun-01	83	61	72	0
01-Jul-01	62	49	56	9
02-Jul-01	82	50	66	0
03-Jul-01	89	55	72	0
04-Jul-01	88	59	74	0
05-Jul-01	97	60	79	0
06-Jul-01	92	66	79	0
07-Jul-01	89	64	76	0
08-Jul-01	89	63	76	0
09-Jul-01	88	66	77	0
10-Jul-01	85	65	75	0
11-Jul-01	84	62	73	0
12-Jul-01	90	59	75	0
13-Jul-01	86	64	75	0
14-Jul-01	95	62	79	0
15-Jul-01	87	62	75	0
16-Jul-01	92	59	76	0
17-Jul-01	100	58	79	0
18-Jul-01	93	56	75	0
19-Jul-01	97	60	79	0
20-Jul-01	98	61	80	0
21-Jul-01	97	64	81	0
22-Jul-01	89	62	76	0
23-Jul-01	88	60	74	0
24-Jul-01	82	60	71	0
25-Jul-01	88	61	75	0
26-Jul-01	79	60	70	0
27-Jul-01	85	58	72	0
28-Jul-01	101	59	80	0
29-Jul-01	89	61	75	0
30-Jul-01	96	61	79	0
31-Jul-01	87	65	76	0

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Temperature Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
01-Aug-01	85	62	74	0
02-Aug-01	99	62	81	0
03-Aug-01	100	64	82	0
04-Aug-01	103	69	86	0
05-Aug-01	96	66	81	0
06-Aug-01	101	65	83	0
07-Aug-01	104	69	87	0
08-Aug-01	97	67	82	0
09-Aug-01	76	55	66	0
10-Aug-01	81	54	68	0
11-Aug-01	87	56	72	0
12-Aug-01	85	59	72	0
13-Aug-01	93	56	75	0
14-Aug-01	81	61	71	0
15-Aug-01	83	57	70	0
16-Aug-01	83	50	67	0
17-Aug-01	89	57	73	0
18-Aug-01	83	50	67	0
19-Aug-01	91	52	72	0
20-Aug-01	92	57	75	0
21-Aug-01	95	62	79	0
22-Aug-01	93	60	77	0
23-Aug-01	91	56	74	0
24-Aug-01	89	55	72	0
25-Aug-01	90	64	77	0
26-Aug-01	94	58	76	0
27-Aug-01	90	55	73	0
28-Aug-01	91	60	76	0
29-Aug-01	83	53	68	0
30-Aug-01	84	51	68	0
31-Aug-01	91	51	71	0
01-Sep-01	95	57	76	0
02-Sep-01	90	56	73	0
03-Sep-01	92	51	72	0
04-Sep-01	103	61	82	0
05-Sep-01	98	64	81	0
06-Sep-01	76	56	66	0
07-Sep-01	69	50	60	5
08-Sep-01	61	37	49	16
09-Sep-01	76	32	54	11
10-Sep-01	82	39	61	4
11-Sep-01	87	49	68	0
12-Sep-01	75	48	62	3
13-Sep-01	58	49	54	11
14-Sep-01	64	51	58	7
15-Sep-01	58	49	54	11

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Temperature Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
16-Sep-01	70	46	58	7
17-Sep-01	63	46	55	10
18-Sep-01	72	49	61	4
19-Sep-01	84	46	65	0
20-Sep-01	72	43	58	7
21-Sep-01	81	41	61	4
22-Sep-01	77	42	60	5
23-Sep-01	60	38	49	16
24-Sep-01	79	35	57	8
25-Sep-01	79	41	60	5
26-Sep-01	82	46	64	1
27-Sep-01	82	52	67	0
28-Sep-01	88	48	68	0
29-Sep-01	77	54	66	0
30-Sep-01	78	46	62	3
01-Oct-01	87	44	66	0
02-Oct-01	77	42	60	5
03-Oct-01	68	35	52	13
04-Oct-01	48	37	43	22
05-Oct-01	52	26	39	26
06-Oct-01	66	25	46	19
07-Oct-01	73	32	53	12
08-Oct-01	71	49	60	5
09-Oct-01	56	44	50	15
10-Oct-01	58	32	45	20
11-Oct-01	61	26	44	21
12-Oct-01	55	34	45	20
13-Oct-01	58	37	48	17
14-Oct-01	54	32	43	22
15-Oct-01	51	22	37	28
16-Oct-01	62	20	41	24
17-Oct-01	81	34	58	7
18-Oct-01	52	32	42	23
19-Oct-01	61	35	48	17
20-Oct-01	59	40	50	15
21-Oct-01	64	32	48	17
22-Oct-01	64	40	52	13
23-Oct-01	70	33	52	13
24-Oct-01	48	30	39	26
25-Oct-01	50	21	36	29
26-Oct-01	54	25	40	25
27-Oct-01	74	27	51	14
28-Oct-01	78	37	58	7
29-Oct-01	48	31	40	25
30-Oct-01	62	37	50	15
31-Oct-01	71	42	57	8

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Temperature Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
01-Nov-01	58	31	45	20
02-Nov-01	64	30	47	18
03-Nov-01	69	35	52	13
04-Nov-01	78	29	54	11
05-Nov-01	75	31	53	12
06-Nov-01	64	38	51	14
07-Nov-01	54	30	42	23
08-Nov-01	66	15	41	24
09-Nov-01	75	21	49	16
10-Nov-01	71	24	48	17
11-Nov-01	65	26	46	19
12-Nov-01	66	32	49	16
13-Nov-01	69	31	50	15
14-Nov-01	69	37	53	12
15-Nov-01	68	32	50	15
16-Nov-01	68	29	49	16
17-Nov-01	71	27	49	16
18-Nov-01	51	18	35	30
19-Nov-01	46	8	27	38
20-Nov-01	66	21	44	21
21-Nov-01	60	29	45	20
22-Nov-01	47	28	38	27
23-Nov-01	52	33	43	22
24-Nov-01	43	32	38	27
25-Nov-01	33	23	28	37
26-Nov-01	23	11	17	48
27-Nov-01	12	-1	6	59
28-Nov-01	11	-4	4	61
29-Nov-01	34	11	23	42
30-Nov-01	37	21	29	36
01-Dec-01	37	12	25	40
02-Dec-01	52	31	42	23
03-Dec-01	60	30	45	20
04-Dec-01	45	24	35	30
05-Dec-01	43	26	35	30
06-Dec-01	43	22	33	32
07-Dec-01	44	22	33	32
08-Dec-01	52	16	34	31
09-Dec-01	58	27	43	22
10-Dec-01	35	22	29	36
11-Dec-01	34	17	26	39
12-Dec-01	36	12	24	41
13-Dec-01	46	11	29	36
14-Dec-01	52	17	35	30
15-Dec-01	41	23	32	33
16-Dec-01	41	14	28	37

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Temperature Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
17-Dec-01	58	22	40	25
18-Dec-01	43	12	28	37
19-Dec-01	50	10	30	35
20-Dec-01	43	18	31	34
21-Dec-01	45	23	34	31
22-Dec-01	26	15	21	44
23-Dec-01	37	7	22	43
24-Dec-01	37	7	22	43
25-Dec-01	35	19	27	38
26-Dec-01	50	22	36	29
27-Dec-01	41	18	30	35
28-Dec-01	31	7	19	46
29-Dec-01	23	6	15	50
30-Dec-01	23	-2	11	54
31-Dec-01	23	-3	10	55
01-Jan-02	17	-3	7	58
02-Jan-02	37	-4	17	48
03-Jan-02	56	10	33	32
04-Jan-02	47	35	41	24
05-Jan-02	45	21	33	32
06-Jan-02	40	20	30	35
07-Jan-02	64	21	43	22
08-Jan-02	72	30	51	14
09-Jan-02	52	32	42	23
10-Jan-02	50	16	33	32
11-Jan-02	51	18	35	30
12-Jan-02	51	12	32	33
13-Jan-02	43	26	35	30
14-Jan-02	31	15	23	42
15-Jan-02	20	3	12	53
16-Jan-02	31	0	16	49
17-Jan-02	29	0	15	50
18-Jan-02	26	4	15	50
19-Jan-02	43	2	23	42
20-Jan-02	44	14	29	36
21-Jan-02	54	21	38	27
22-Jan-02	48	23	36	29
23-Jan-02	40	9	25	40
24-Jan-02	49	11	30	35
25-Jan-02	60	28	44	21
26-Jan-02	65	29	47	18
27-Jan-02	42	14	28	37
28-Jan-02	14	3	9	56
29-Jan-02	20	-3	9	56
30-Jan-02	33	0	17	48
31-Jan-02	34	1	18	47

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Temperature Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
01-Feb-02	48	11	30	35
02-Feb-02	45	17	31	34
03-Feb-02	42	15	29	36
04-Feb-02	45	9	27	38
05-Feb-02	55	9	32	33
06-Feb-02	55	18	37	28
07-Feb-02	61	25	43	22
08-Feb-02	60	19	40	25
09-Feb-02	28	10	19	46
10-Feb-02	45	6	26	39
11-Feb-02	54	29	42	23
12-Feb-02	40	15	28	37
13-Feb-02	59	12	36	29
14-Feb-02	49	20	35	30
15-Feb-02	54	15	35	30
16-Feb-02	59	25	42	23
17-Feb-02	63	22	43	22
18-Feb-02	48	27	38	27
19-Feb-02	44	22	33	32
20-Feb-02	50	16	33	32
21-Feb-02	49	26	38	27
22-Feb-02	69	24	47	18
23-Feb-02	50	24	37	28
24-Feb-02	25	12	19	46
25-Feb-02	11	1	6	59
26-Feb-02	21	-1	10	55
27-Feb-02	31	1	16	49
28-Feb-02	29	-2	14	51
01-Mar-02	8	-4	2	63
02-Mar-02	11	-4	4	61
03-Mar-02	35	-3	16	49
04-Mar-02	46	27	37	28
05-Mar-02	55	24	40	25
06-Mar-02	25	12	19	46
07-Mar-02	21	13	17	48
08-Mar-02	14	-1	7	58
09-Mar-02	31	-14	9	56
10-Mar-02	31	5	18	47
11-Mar-02	57	17	37	28
12-Mar-02	67	37	52	13
13-Mar-02	37	26	32	33
14-Mar-02	26	11	19	46
15-Mar-02	30	4	17	48
16-Mar-02	33	8	21	44
17-Mar-02	30	24	27	38
18-Mar-02	26	17	22	43

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Temperature Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
19-Mar-02	28	16	22	43
20-Mar-02	24	6	15	50
21-Mar-02	11	-4	4	61
22-Mar-02	24	-4	10	55
23-Mar-02	27	15	21	44
24-Mar-02	23	14	19	46
25-Mar-02	20	11	16	49
26-Mar-02	33	3	18	47
27-Mar-02	47	20	34	31
28-Mar-02	44	22	33	32
29-Mar-02	45	28	37	28
30-Mar-02	46	30	38	27
31-Mar-02	52	26	39	26
01-Apr-02	56	21	39	26
02-Apr-02	23	13	18	47
03-Apr-02	31	8	20	45
04-Apr-02	49	13	31	34
05-Apr-02	57	23	40	25
06-Apr-02	81	33	57	8
07-Apr-02	58	38	48	17
08-Apr-02	45	32	39	26
09-Apr-02	73	31	52	13
10-Apr-02	58	41	50	15
11-Apr-02	59	38	49	16
12-Apr-02	71	35	53	12
13-Apr-02	77	44	61	4
14-Apr-02	83	42	63	2
15-Apr-02	67	46	57	8
16-Apr-02	59	28	44	21
17-Apr-02	73	28	51	14
18-Apr-02	59	28	44	21
19-Apr-02	42	29	36	29
20-Apr-02	40	29	35	30
21-Apr-02	45	28	37	28
22-Apr-02	66	28	47	18
23-Apr-02	79	32	56	9
24-Apr-02	52	30	41	24
25-Apr-02	52	22	37	28
26-Apr-02	62	22	42	23
27-Apr-02	45	36	41	24
28-Apr-02	62	35	49	16
29-Apr-02	66	37	52	13
30-Apr-02	52	41	47	18
01-May-02	43	28	36	29
02-May-02	63	30	47	18
03-May-02	75	33	54	11

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

	Temperature			
Date	Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
04-May-02	63	28	46	19
05-May-02	66	41	54	11
06-May-02	53	34	44	21
07-May-02	38	32	35	30
08-May-02	53	33	43	22
09-May-02	55	25	40	25
10-May-02	60	39	50	15
11-May-02	45	35	40	25
12-May-02	65	33	49	16
13-May-02	69	38	54	11
14-May-02	82	41	62	3
15-May-02	67	52	60	5
16-May-02	53	43	48	17
17-May-02	55	39	47	18
18-May-02	62	39	51	14
19-May-02	65	38	52	13
20-May-02	67	41	54	11
21-May-02	80	50	65	0
22-May-02	65	39	52	13
23-May-02	48	24	36	29
24-May-02	59	23	41	24
25-May-02	73	36	55	10
26-May-02	75	46	61	4
27-May-02	76	47	62	3
28-May-02	82	49	66	0
29-May-02	82	55	69	0
30-May-02	89	56	73	0
31-May-02	83	51	67	0
01-Jun-02	82	55	69	0
02-Jun-02	71	48	60	5
03-Jun-02	67	50	59	6
04-Jun-02	71	44	58	7
05-Jun-02	82	40	61	4
06-Jun-02	87	48	68	0
07-Jun-02	77	52	65	0
08-Jun-02	86	54	70	0
09-Jun-02	80	58	69	0
10-Jun-02	81	52	67	0
11-Jun-02	74	44	59	6
12-Jun-02	73	46	60	5
13-Jun-02	74	46	60	5
14-Jun-02	80	43	62	3
15-Jun-02	81	50	66	0
16-Jun-02	89	48	69	0
17-Jun-02	90	58	74	0
18-Jun-02	86	60	73	0

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Actual Daily Temperature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Temperature Hi	Low	Avg	HDD 65
(B)	(C)	(D)	(E)	(F)
19-Jun-02	79	48	64	1
20-Jun-02	82	43	63	2
21-Jun-02	93	61	77	0
22-Jun-02	97	63	80	0
23-Jun-02	95	56	76	0
24-Jun-02	95	61	78	0
25-Jun-02	96	64	80	0
26-Jun-02	94	59	77	0
27-Jun-02	101	58	80	0
28-Jun-02	108	62	85	0
29-Jun-02	109	68	89	0
30-Jun-02	94	68	81	0

Source:
Column (C) and (D): NOAA Climatological Data South Dakota Volume106 No. 5 to Volume 107 No.6
Column (E): (Column (C) + Colund (D))/2
Column (F): 65 - Column (F).
Note: Negative values are shown as a 0 in Column (F)

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date (A)	Normal Average Temperature (B)	Normal HDD65 (C)
01-May-01	50	15
02-May-01	50	15
03-May-01	50	15
04-May-01	51	14
05-May-01	51	14
06-May-01	51	14
07-May-01	52	13
08-May-01	52	13
09-May-01	52	13
10-May-01	53	12
11-May-01	53	12
12-May-01	54	11
13-May-01	54	11
14-May-01	54	11
15-May-01	55	10
16-May-01	55	10
17-May-01	55	10
18-May-01	56	9
19-May-01	57	8
20-May-01	57	8
21-May-01	57	8
22-May-01	57	8
23-May-01	58	7
24-May-01	58	7
25-May-01	58	7
26-May-01	59	7
27-May-01	59	7
28-May-01	59	6
29-May-01	59	6
30-May-01	60	6
31-May-01	60	6
01-Jun-01	60	6
02-Jun-01	60	6
03-Jun-01	60	6
04-Jun-01	61	5
05-Jun-01	61	5
06-Jun-01	61	5
07-Jun-01	62	4
08-Jun-01	63	4
09-Jun-01	63	4

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
10-Jun-01	63	4
11-Jun-01	63	3
12-Jun-01	64	3
13-Jun-01	64	3
14-Jun-01	64	2
15-Jun-01	65	2
16-Jun-01	65	2
17-Jun-01	65	2
18-Jun-01	65	2
19-Jun-01	66	2
20-Jun-01	66	2
21-Jun-01	67	2
22-Jun-01	67	2
23-Jun-01	67	2
24-Jun-01	67	2
25-Jun-01	67	2
26-Jun-01	67	2
27-Jun-01	68	1
28-Jun-01	69	1
29-Jun-01	69	1
30-Jun-01	69	1
01-Jul-01	69	1
02-Jul-01	69	1
03-Jul-01	70	1
04-Jul-01	70	1
05-Jul-01	70	1
06-Jul-01	70	1
07-Jul-01	70	1
08-Jul-01	71	1
09-Jul-01	71	1
10-Jul-01	71	1
11-Jul-01	71	1
12-Jul-01	71	1
13-Jul-01	72	1
14-Jul-01	72	1
15-Jul-01	72	1
16-Jul-01	72	1
17-Jul-01	72	0
18-Jul-01	72	0
19-Jul-01	72	0

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
20-Jul-01	73	0
21-Jul-01	73	0
22-Jul-01	73	0
23-Jul-01	73	0
24-Jul-01	73	0
25-Jul-01	73	0
26-Jul-01	73	0
27-Jul-01	73	0
28-Jul-01	73	0
29-Jul-01	73	0
30-Jul-01	73	0
31-Jul-01	73	0
01-Aug-01	73	0
02-Aug-01	73	0
03-Aug-01	73	0
04-Aug-01	73	0
05-Aug-01	73	0
06-Aug-01	73	0
07-Aug-01	73	0
08-Aug-01	73	0
09-Aug-01	73	0
10-Aug-01	73	0
11-Aug-01	73	0
12-Aug-01	72	0
13-Aug-01	72	0
14-Aug-01	72	0
15-Aug-01	72	0
16-Aug-01	72	0
17-Aug-01	71	1
18-Aug-01	71	1
19-Aug-01	71	1
20-Aug-01	71	1
21-Aug-01	70	1
22-Aug-01	70	1
23-Aug-01	70	1
24-Aug-01	70	1
25-Aug-01	69	1
26-Aug-01	69	2
27-Aug-01	69	2
28-Aug-01	68	2

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date (A)	Normal Average Temperature (B)	Normal HDD65 (C)
29-Aug-01	68	2
30-Aug-01	67	2
31-Aug-01	67	2
01-Sep-01	66	3
02-Sep-01	66	3
03-Sep-01	66	3
04-Sep-01	65	3
05-Sep-01	65	3
06-Sep-01	64	4
07-Sep-01	64	4
08-Sep-01	64	4
09-Sep-01	63	5
10-Sep-01	63	5
11-Sep-01	62	5
12-Sep-01	62	5
13-Sep-01	62	5
14-Sep-01	61	6
15-Sep-01	61	6
16-Sep-01	60	6
17-Sep-01	60	7
18-Sep-01	60	7
19-Sep-01	59	7
20-Sep-01	59	7
21-Sep-01	58	8
22-Sep-01	58	8
23-Sep-01	58	8
24-Sep-01	57	9
25-Sep-01	57	9
26-Sep-01	56	10
27-Sep-01	56	10
28-Sep-01	56	10
29-Sep-01	55	10
30-Sep-01	55	10
01-Oct-01	55	10
02-Oct-01	54	11
03-Oct-01	54	11
04-Oct-01	54	11
05-Oct-01	53	12
06-Oct-01	53	12
07-Oct-01	52	13

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date (A)	Normal Average Temperature (B)	Normal HDD65 (C)
08-Oct-01	52	13
09-Oct-01	52	13
10-Oct-01	51	14
11-Oct-01	51	14
12-Oct-01	50	15
13-Oct-01	50	15
14-Oct-01	49	16
15-Oct-01	49	16
16-Oct-01	48	17
17-Oct-01	48	17
18-Oct-01	47	18
19-Oct-01	47	18
20-Oct-01	47	18
21-Oct-01	46	19
22-Oct-01	46	19
23-Oct-01	45	20
24-Oct-01	45	20
25-Oct-01	44	21
26-Oct-01	43	22
27-Oct-01	43	22
28-Oct-01	42	23
29-Oct-01	42	23
30-Oct-01	41	24
31-Oct-01	41	24
01-Nov-01	40	25
02-Nov-01	40	25
03-Nov-01	39	26
04-Nov-01	38	26
05-Nov-01	38	27
06-Nov-01	37	27
07-Nov-01	37	28
08-Nov-01	36	28
09-Nov-01	36	29
10-Nov-01	35	29
11-Nov-01	35	29
12-Nov-01	35	30
13-Nov-01	34	30
14-Nov-01	34	31
15-Nov-01	33	31
16-Nov-01	33	32

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date (A)	Normal Average Temperature (B)	Normal HDD65 (C)
17-Nov-01	32	32
18-Nov-01	32	32
19-Nov-01	32	33
20-Nov-01	31	33
21-Nov-01	31	33
22-Nov-01	31	34
23-Nov-01	30	34
24-Nov-01	30	35
25-Nov-01	29	35
26-Nov-01	29	35
27-Nov-01	29	36
28-Nov-01	29	36
29-Nov-01	28	36
30-Nov-01	28	37
01-Dec-01	28	37
02-Dec-01	28	37
03-Dec-01	27	37
04-Dec-01	27	37
05-Dec-01	27	37
06-Dec-01	27	38
07-Dec-01	26	38
08-Dec-01	26	38
09-Dec-01	26	38
10-Dec-01	26	39
11-Dec-01	25	39
12-Dec-01	25	39
13-Dec-01	25	39
14-Dec-01	25	40
15-Dec-01	25	40
16-Dec-01	24	40
17-Dec-01	24	40
18-Dec-01	24	40
19-Dec-01	24	41
20-Dec-01	24	41
21-Dec-01	24	41
22-Dec-01	24	41
23-Dec-01	23	41
24-Dec-01	23	41
25-Dec-01	23	41
26-Dec-01	23	42

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
27-Dec-01	23	42
28-Dec-01	23	42
29-Dec-01	23	42
30-Dec-01	22	42
31-Dec-01	22	43
01-Jan-02	22	43
02-Jan-02	22	43
03-Jan-02	22	43
04-Jan-02	22	43
05-Jan-02	22	43
06-Jan-02	22	43
07-Jan-02	22	43
08-Jan-02	22	43
09-Jan-02	22	43
10-Jan-02	22	43
11-Jan-02	22	43
12-Jan-02	22	43
13-Jan-02	22	43
14-Jan-02	22	43
15-Jan-02	22	43
16-Jan-02	22	43
17-Jan-02	22	43
18-Jan-02	22	42
19-Jan-02	22	42
20-Jan-02	22	42
21-Jan-02	22	42
22-Jan-02	22	42
23-Jan-02	23	42
24-Jan-02	23	42
25-Jan-02	23	42
26-Jan-02	23	42
27-Jan-02	23	41
28-Jan-02	24	41
29-Jan-02	24	41
30-Jan-02	24	41
31-Jan-02	24	41
01-Feb-02	24	41
02-Feb-02	24	41
03-Feb-02	25	40
04-Feb-02	25	40

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
05-Feb-02	25	40
06-Feb-02	25	40
07-Feb-02	26	40
08-Feb-02	26	39
09-Feb-02	26	39
10-Feb-02	26	39
11-Feb-02	26	39
12-Feb-02	27	39
13-Feb-02	27	38
14-Feb-02	27	38
15-Feb-02	27	38
16-Feb-02	28	38
17-Feb-02	28	37
18-Feb-02	28	37
19-Feb-02	28	37
20-Feb-02	29	37
21-Feb-02	29	36
22-Feb-02	29	36
23-Feb-02	29	36
24-Feb-02	30	36
25-Feb-02	30	35
26-Feb-02	30	35
27-Feb-02	30	35
28-Feb-02	30	35
01-Mar-02	30	35
02-Mar-02	30	34
03-Mar-02	31	34
04-Mar-02	31	34
05-Mar-02	32	33
06-Mar-02	32	33
07-Mar-02	32	32
08-Mar-02	33	32
09-Mar-02	33	32
10-Mar-02	33	32
11-Mar-02	33	31
12-Mar-02	34	31
13-Mar-02	34	31
14-Mar-02	34	30
15-Mar-02	35	30
16-Mar-02	35	30

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
17-Mar-02	35	29
18-Mar-02	36	29
19-Mar-02	36	29
20-Mar-02	36	29
21-Mar-02	36	28
22-Mar-02	37	28
23-Mar-02	37	28
24-Mar-02	37	27
25-Mar-02	38	27
26-Mar-02	38	27
27-Mar-02	38	27
28-Mar-02	39	26
29-Mar-02	39	26
30-Mar-02	39	26
31-Mar-02	40	25
01-Apr-02	40	25
02-Apr-02	40	24
03-Apr-02	41	24
04-Apr-02	41	24
05-Apr-02	41	23
06-Apr-02	42	23
07-Apr-02	42	23
08-Apr-02	42	22
09-Apr-02	42	22
10-Apr-02	43	22
11-Apr-02	43	21
12-Apr-02	43	21
13-Apr-02	44	21
14-Apr-02	44	20
15-Apr-02	45	20
16-Apr-02	45	20
17-Apr-02	45	19
18-Apr-02	46	19
19-Apr-02	46	19
20-Apr-02	46	18
21-Apr-02	47	18
22-Apr-02	47	18
23-Apr-02	47	17
24-Apr-02	48	17
25-Apr-02	48	17

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date (A)	Normal Average Temperature (B)	Normal HDD65 (C)
26-Apr-02	48	16
27-Apr-02	49	16
28-Apr-02	49	16
29-Apr-02	49	15
30-Apr-02	50	15
01-May-02	50	15
02-May-02	50	15
03-May-02	50	15
04-May-02	51	14
05-May-02	51	14
06-May-02	51	14
07-May-02	52	13
08-May-02	52	13
09-May-02	52	13
10-May-02	53	12
11-May-02	53	12
12-May-02	54	11
13-May-02	54	11
14-May-02	54	11
15-May-02	55	10
16-May-02	55	10
17-May-02	55	10
18-May-02	56	9
19-May-02	57	8
20-May-02	57	8
21-May-02	57	8
22-May-02	57	8
23-May-02	58	7
24-May-02	58	7
25-May-02	58	7
26-May-02	59	7
27-May-02	59	7
28-May-02	59	6
29-May-02	59	6
30-May-02	60	6
31-May-02	60	6
01-Jun-02	60	6
02-Jun-02	60	6
03-Jun-02	60	6
04-Jun-02	61	5

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

Montana-Dakota Utilities
South Dakota - Gas
Normal Temeprature and HDD Data
Rapid City APO
May 1, 2001 to June 30, 2002

Date	Normal Average Temperature	Normal HDD65
(A)	(B)	(C)
05-Jun-02	61	5
06-Jun-02	61	5
07-Jun-02	62	4
08-Jun-02	63	4
09-Jun-02	63	4
10-Jun-02	63	4
11-Jun-02	63	3
12-Jun-02	64	3
13-Jun-02	64	3
14-Jun-02	64	2
15-Jun-02	65	2
16-Jun-02	65	2
17-Jun-02	65	2
18-Jun-02	65	2
19-Jun-02	66	2
20-Jun-02	66	2
21-Jun-02	67	2
22-Jun-02	67	2
23-Jun-02	67	2
24-Jun-02	67	2
25-Jun-02	67	2
26-Jun-02	67	2
27-Jun-02	68	1
28-Jun-02	69	1
29-Jun-02	69	1
30-Jun-02	69	1

Source: Rapid City DD 0701to0602 - Adjusted.xls
Column (B) and (C): NWSO Website http://www.crh.noaa.gov/unr/climate/index.htm Daily Normals

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

RECEIVED
APR 2 2 2003
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Montana-Dakota Utilities Co.
Application to Increase Gas Rates in South Dakota
Docket No. NG02-011

Testimony
Of
Basil L. Copeland Jr.
On Behalf of the Commission Staff

April 2003

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Montana-Dakota Utilities Co.
Application to Increase Gas Rates in South Dakota
Docket No. NG02-011

Testimony
Of
Basil L. Copeland Jr.
On Behalf of the Commission Staff

April 2003

I. BACKGROUND AND QUALIFICATIONS

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., Columbia, 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 by 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 which included 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] deals 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?

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[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).

1 A. My testimony presents evidence concerning the cost of capital for Montana-Dakota
2 Utilities ("MDU"), and recommends a fair and reasonable rate of return based upon
3 that evidence. I also review and respond to MDU's presentation of evidence
4 concerning the cost of capital.

5 **Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COST OF**
6 **CAPITAL AND YOUR RECOMMENDED RATE OF RETURN.**

7 A. I conclude that the cost of equity capital for MDU is in the range of 9.0 to 10.0
8 percent. In order to maintain a pro forma interest coverage ratio of 3.0 or better, I
9 recommend a rate of return on equity of 9.75 percent. Using my recommended rate
10 of return on equity and the capital structure and senior capital costs of the Company,
11 I recommend an overall rate of return of 9.243 percent. Exhibit __(BLC-1), Schedule
12 1 presents the details of this calculation.

13 **III. OVERALL RATE OF RETURN AND THE COST OF EQUITY**

14 **Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN RATE OF RETURN AND THE**
15 **COST OF EQUITY.**

16 A. Typically, regulated utilities have utilized three sources of capital to capitalize their
17 utility assets: common stock, preferred stock, and long-term debt. The rate of return
18 for a regulated firm is usually based on its "weighted average cost of capital." This
19 weighted average cost of capital represents the cost of the individual sources of
20 capital weighted by their proportion as represented in the capital structure. The cost
21 of equity, and my recommended return on equity of 9.75 percent, is one component
22 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. 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 do 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

1 believe that it is proper to rely upon the sample of companies utilized by MDU's
2 witness to estimate the cost of capital to MDU.

3 **Q. PLEASE EXPLAIN WHY NOT.**

4 A. MDU's rate of return witness, J. Stephen Gaske, developed his recommendation
5 using a sample based upon Moody's Natural Gas Distribution Companies. While this
6 docket concerns a requested gas rate increase, the proper rate of return on equity is
7 one which is fair to MDU's shareholders, and not necessarily to a particular segment
8 of the business. The applicable standard under Hope as to what is fair from the
9 investor point of view is that the return be commensurate with what the investors
10 could reasonably expect to earn on investments of comparable risk. Investors
11 cannot invest in just the gas distribution operations of MDU. They must invest in
12 MDU as a whole. Thus the relevant standard of comparability is to operations
13 comparable to MDU as a whole. In my opinion, this requires that the sample of
14 comparable companies be combination utilities with combined gas and electric
15 operations similar to MDU. For this reason, I have used a sample of 20 electric
16 utilities with gas distribution operations.

17 **Q. WHAT DATA DID YOU EXAMINE IN ORDER TO ESTIMATE THE INVESTOR**
18 **EXPECTED GROWTH RATE FOR YOUR DCF ANALYSIS?**

19 A. For my constant growth DCF study, I utilized the Zacks consensus estimate of
20 projected growth in earnings per share ("EPS"), and Value Line estimates of growth
21 in dividends per share ("DPS"), growth in book value per share ("BVPS"), and the
22 Value Line estimate of "% Retained to Common Equity" (a measure of long term

1 sustainable growth).[3] Theoretically, if the constant growth assumptions are valid,
2 earnings, dividends, and book value per share should all grow at approximately the
3 same rate. Where this is the case, it is sometimes possible to derive reasonable and
4 accurate estimates of the cost of equity using only one of these growth measures as
5 a "proxy" for the expected rate of growth in dividends. But if the payout ratio is not
6 constant, using just projected earnings or dividend growth can result in distorted
7 estimates of the DCF cost of equity.

8 **Q. WHAT ARE YOUR ESTIMATES OF THE PROJECTED GROWTH RATES FOR**
9 **THESE MEASURES?**

10 A. The projected growth rates used in my constant growth DCF study are shown on
11 Exhibit BLC-1, Schedule 2. As can be seen from Columns F and G, there is
12 considerable disparity between the EPS growth rates projected by Zacks and the
13 DPS growth rates projected by Value Line. The projected EPS growth rates are on
14 average substantially higher than the DPS growth rates. This disparity reflects a
15 projected near-term decline in dividend payout, resulting in a rise in the earnings
16 retention rate. But the constant growth DCF model is a model of investors' long-term
17 dividend growth expectations. Consequently, based on current market conditions,
18 relying solely upon projected EPS growth rates will overstate the investors' long-term

[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 equivalent to the "br" measure of expected dividend growth used in some presentations of the DCF model.

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) 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. 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

[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

1 I, we avoid the bias that arises from relying solely upon a single measure of expected
2 growth. The mean estimate of "k" is 9.85 percent, and the median estimate of "k" is
3 9.83 percent. The difference between the median and the mean reflects the impact
4 of "outliers" or atypical observations in the calculation of the mean. For that reason
5 the median is the more reliable measure of central tendency.

6 **Q. DID YOU UNDERTAKE ANY ADDITIONAL DCF ANALYSIS?**

7 A. Yes, I did. In addition to the more traditional form of the DCF methodology, I
8 developed DCF estimates using a "dividend discount model" (DDM). Dividend
9 discount models are more general forms of the DCF methodology, which embody
10 less restrictive assumptions than the traditional methodology. The traditional
11 methodology is sometimes referred to as the "constant growth model," and assumes
12 that dividends, earnings, book value per share, and share price all grow at the same
13 uniform rate of growth in perpetuity. While this is rarely the case in actuality, it is not
14 an unreasonable assumption if the differences are small, a condition which implicitly
15 requires a relatively constant dividend payout ratio. Where dividend payout ratios
16 are expected to trend upward or downward over extended periods of time, use of
17 five-year growth projections of the type published by Zacks, Value Line, or other
18 investment services in a constant growth form of the DCF model can produce
19 distorted and unreliable results. Multiple-period dividend discount models provide

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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.

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 postponing the period of constant growth to 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 use such models to develop expected returns, which are 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 2003, the current Zacks consensus EPS growth projection, an estimate of long-term growth into perpetuity, and estimated retention ratios for 2003, 2007, and 2022. The DDM analysis assumes that earnings grow from 2003 to 2007 at the indicated Zacks consensus EPS growth rate, and at the long-term growth rate (5.50 percent, the median value of Value Line's "% Retained to Common Equity") thereafter. The period from 2007 to 2022 is a transition period during which the payout ratio changes from the value projected by Value Line in the year 2007 to a common value of 0.49 (the median Value Line estimate for 2007) for all companies in the sample in the year 2022. Constant growth assumptions — long-term growth 5.50 percent, and a retention ratio of 0.49 percent — apply after the year 2022, allowing the determination of a terminal share price for the year 2022. These long-term conditions after 2022 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 return for the 20 company sample are both 9.88 percent. These results corroborate the results of the constant growth analysis.

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 4. These data indicate that for the last 76 years, common stocks have earned a long-horizon risk premium over long-term U.S. Treasury bonds of about 5.49 percent, 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 median beta coefficient (as computed by Value Line) for the sample of comparable combination utilities is 0.675. Using a 5.49 percent market risk premium, and a recent long-term (30-year) U.S. Treasury bond yield of 4.9 percent[6], the resulting CAPM estimate of the cost of equity is:

$$k = 4.90 + (0.675 \times 5.49) = 4.90 + 3.71 = 8.61 \text{ percent.}$$

[6] For consistency's sake, I determine the interest rate for the risk free portion of the CAPM the same way I determine the stock price for the dividend yield component of the DCF return, e.g., by using a

1 This result corroborates the reasonableness of my DCF estimates, and provides
2 additional evidence of a reasonable range for the Company's cost of equity.
3 **Q. CONSIDERING THE EVIDENCE YOU PRESENT, WHAT IS YOUR ESTIMATE OF**
4 **THE COST OF EQUITY FOR MDU?**
5 A. Based upon the evidence presented above, I conclude that the cost of equity for
6 MDU is presently in the range of 9.0 to 10.0 percent.
7 **V. ANALYSIS OF MDU RATE OF RETURN TESTIMONY**
8 **Q. HAVE YOU REVIEWED THE TESTIMONY AND EXHIBITS OF J. STEPHEN**
9 **GASKE, THE WITNESS SPONSORING MDU'S REQUESTED RETURN ON**
10 **EQUITY?**
11 A. Yes, I have.
12 **Q. PLEASE COMMENT ON THE EVIDENCE SUBMITTED BY DR. GASKE IN**
13 **SUPPORT OF HIS RATE OF RETURN RECOMMENDATION.**
14 **A.** Dr. Gaske begins his presentation with the DCF method, which he applies to a
15 sample of natural gas distribution companies. I have already stated why I believe
16 that this is an inappropriate sample for estimating the cost of equity for MDU. So
17 whatever other merit his studies might have, he is not, in my opinion, estimating the
18 cost of equity capital for MDU. But beyond that, I do see significant problems with
19 the way he implements his DCF analyses. His first DCF approach is described as a
20 "Second-Stage Retention Growth" analysis. Superficially, this seems to be an
21 attempt to implement a two-stage dividend discount model similar to the DDM that I

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180 day moving average as long as this 180 day moving average is within two standard deviations of

1 describe earlier in my testimony. But it is fundamentally flawed because it relies
2 solely upon projected earnings growth rates for the initial, near term stage. This is
3 not merely a fundamental flaw, but a fatal one. After all, the "D" in "DCF" represents
4 the dividend cash flow to the investor, and Dr. Gaske has not presented one iota of
5 evidence regarding projected dividend growth. While dividends are arguably paid out
6 of earnings, earnings growth is a reasonable proxy for dividend growth only if the
7 payout ratio is constant, an assumption simply not borne out under current market
8 conditions. Dr. Gaske's second DCF method, described as "a Basic DCF method"
9 merely compounds this flaw, since it relies solely upon near-term earnings forecasts
10 for both the near-term and the long-term. Because Dr. Gaske has made no use of
11 any evidence with respect to investor expectations regarding dividend growth, it is
12 impossible for him to have reliably or accurately implemented the DCF model.
13
14 **Q. PLEASE DISCUSS DR. GASKE'S RISK PREMIUM APPROACHES.**
15 A. Dr. Gaske employs two risk premium approaches which share a common weakness:
16 utilization of simple arithmetic averages to estimate the historical risk premium. The
17 correct approach will make use of geometric averages for appropriate long-horizon
18 holding periods.[7]
19 **Q. DR. GASKE ALSO DISCUSSES THE RETURNS ON ALTERNATIVE EQUITY**
20 **INVESTMENTS. PLEASE COMMENT.**

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a 20 day moving average. The data used for this determination was as of 4-21-03.
[7]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.

1 A. The evidence that Dr. Gaske presents regarding "alternative equity investments" is of
2 no value whatsoever to determining the fair rate of return and cost of equity for MDU.
3 First of all, the data that he presents represents returns on book equity. Investors
4 cannot purchase stock at book value (unless the market-to-book ratio is 1.0); they
5 must purchase stock at market value. Hence, investors do not have the opportunity
6 to earn these book returns. They only have the opportunity to earn the equilibrium
7 market return. That is why commissions and regulatory agencies long ago discarded
8 the "comparable earnings" approach and adopted the DCF approach. While he
9 declines to describe it as such, Dr. Gaske's "alternative equity investment analysis" is
10 nothing more than a "comparable earnings" analysis under the guise of a different
11 name. But it is still just as flawed.
12 Secondly, these are not the returns on investments of comparable risk. The
13 two measures that Dr. Gaske employs – the S&P 500, and 746 industrial, retail, and
14 transportations published by Value Line – are too broad to represent the return on
15 investments of comparable risk. Hence there is no way that this evidence can be
16 helpful in determining a reasonable rate of return for MDU.
17 **Q. PLEASE SUMMARIZE YOUR COMMENTS ON DR. GASKE'S TESTIMONY.**
18 A. In my opinion, Dr. Gaske has failed to present any meaningful evidence of the cost of
19 equity or fair rate of return on equity for MDU.
20 **Q. DOES THAT COMPLETE YOUR TESTIMONY AT THE PRESENT TIME?**
21 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.

Exhibit____(BLC-1)
Schedule 1

Montana-Dakota Utilities Co.
Proposed Capital Structure and Rate of Return

Line No.	Source	% of Total	Cost Rate	Wtd Cost
	A	B	C	D
1	Long-Term Debt	43.441%	9.211%	4.001%
2	Preferred Stock	5.330%	4.624%	0.246%
3	Common Equity	51.229%	9.750%	4.995%
4	Total	100.000%		9.243%

MONTANA-DAKOTA UTILITIES CO.
DCF Rate of Return Analysis Using Dividend Cash Flow Model (Constant Growth)

Company	Dividend 2003	Dividend 2004	Stock Price	Dividend Yield	Proj. EPS Growth (Zacks)	Proj. DPS Growth (VL)	Proj. BVPS Growth (VL)	% Ret. To Com. Eq. (VL)	Proj Payout Ratio 2003	Proj Payout Ratio 2007	DCF Cost of Equity k
A	B	C	D	E	F	G	H	I	J	K	L
Ameren Corp	2.54	2.54	40.00	6.35%	4.00%	1.35%	2.47%	2.00%	87.59%	81.21%	8.80%
Cinergy Corp.	1.84	1.88	32.50	5.72%	5.00%	2.11%	4.87%	4.00%	69.43%	65.57%	9.72%
CH Energy Group	2.16	2.16	43.00	5.02%	5.00%	0.46%	0.49%	2.50%	83.08%	73.33%	7.14%
Consol. Edison	2.24	2.26	40.00	5.63%	3.00%	0.88%	3.57%	3.00%	74.67%	69.25%	8.24%
Constellation Energy	1.04	1.14	27.50	3.96%	7.00%	7.33%	8.05%	8.50%	38.52%	32.47%	11.68%
Dominion Resources	2.58	2.58	55.50	4.65%	6.00%	1.14%	7.08%	6.50%	53.75%	46.96%	9.83%
DTE Energy	2.06	2.06	42.00	4.90%	6.00%	0.48%	7.55%	7.00%	52.15%	44.21%	10.16%
Energy East	1.00	1.04	20.00	5.10%	5.00%	3.78%	4.53%	4.50%	57.14%	58.00%	9.55%
Entergy	1.42	1.50	46.00	3.17%	7.00%	5.21%	6.15%	5.50%	36.88%	39.55%	9.14%
Exelon	1.84	1.92	50.00	3.76%	5.00%	3.97%	13.19%	10.50%	36.80%	30.94%	11.93%
NISOURCE	1.16	1.16	19.00	6.11%	5.00%	0.85%	3.76%	4.00%	66.29%	60.00%	9.51%
Northeast Utilities	0.57	0.63	15.00	4.00%	4.00%	9.18%	4.59%	6.00%	47.50%	39.51%	9.94%
NSTAR	2.17	2.21	41.00	5.34%	4.00%	1.79%	4.33%	5.50%	63.82%	58.25%	9.25%
PNM	0.91	0.95	22.50	4.13%	5.00%	4.37%	3.82%	4.00%	55.15%	46.96%	8.43%
PS Enterprise Group	2.16	2.16	36.00	6.00%	5.00%	1.80%	10.50%	7.00%	56.84%	50.43%	12.08%
SCANA Corp	1.38	1.46	30.00	4.73%	5.00%	5.35%	5.86%	5.50%	53.08%	52.31%	10.16%
Sempra	1.00	1.00	23.50	4.26%	6.00%	0.00%	12.14%	9.00%	37.74%	33.33%	11.04%
Vectran	1.11	1.27	22.00	5.41%	6.00%	3.42%	5.43%	5.00%	61.67%	57.73%	10.37%
Wisconsin Energy	0.80	0.80	24.00	3.33%	7.00%	5.74%	8.44%	6.50%	34.04%	36.36%	10.25%
WPS Resources	2.16	2.32	39.00	5.74%	5.00%	1.80%	3.63%	3.50%	75.79%	68.24%	9.23%
			Mean:	**4.87%**	**5.25%**	**3.12%**	**6.02%**	**5.50%**	**57.10%**	**52.23%**	**9.85%**
			Median:	**4.90%**	**5.00%**	**2.11%**	**5.43%**	**5.50%**	**55.15%**	**50.43%**	**9.83%**
				Std Error:	**0.30%**	**0.74%**	**0.80%**				**0.31%**

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

MONTANA-DAKOTA UTILITIES CO.
DCF Rate of Return Analysis Using Dividend Discount Model (DDM)

Company	Inputs:							Output:
	Dividend Yield	2003 EPS	Zacks Growth	Long-Term Growth	Retention Ratios 2003	2007	2022	DDM Return
Ameren Corp	6.35%	2.90	4.00%	5.50%	0.12	0.19	0.49	9.76%
Cinergy Corp.	5.72%	2.65	5.00%	5.50%	0.31	0.34	0.49	10.05%
CH Energy Group	5.02%	2.60	5.00%	5.50%	0.17	0.27	0.49	8.92%
Consol. Edison	5.63%	3.00	3.00%	5.50%	0.25	0.31	0.49	9.43%
Constellation Energy	3.96%	2.70	7.00%	5.50%	0.61	0.68	0.49	10.20%
Dominion Resources	4.65%	4.80	6.00%	5.50%	0.46	0.53	0.49	9.83%
DTE Energy	4.90%	3.95	6.00%	5.50%	0.48	0.56	0.49	10.11%
Energy East	5.10%	1.75	5.00%	5.50%	0.43	0.42	0.49	10.13%
Entergy	3.17%	3.85	7.00%	5.50%	0.63	0.60	0.49	9.64%
Exelon	3.76%	5.00	5.00%	5.50%	0.63	0.69	0.49	9.83%
NISOURCE	6.11%	1.75	5.00%	5.50%	0.34	0.40	0.49	10.44%
Northeast Utilities	4.00%	1.20	4.00%	5.50%	0.53	0.60	0.49	9.23%
NSTAR	5.34%	3.40	4.00%	5.50%	0.36	0.42	0.49	9.73%
PNM	4.13%	1.65	5.00%	5.50%	0.45	0.53	0.49	9.13%
PS Enterprise Group	6.00%	3.80	5.00%	5.50%	0.43	0.50	0.49	10.76%
SCANA Corp	4.73%	2.60	5.00%	5.50%	0.47	0.48	0.49	9.94%
Sempra	4.26%	2.65	6.00%	5.50%	0.62	0.67	0.49	10.47%
Vectran	5.41%	1.80	6.00%	5.50%	0.38	0.42	0.49	10.25%
Wisconsin Energy	3.33%	2.35	7.00%	5.50%	0.66	0.64	0.49	10.06%
WPS Resources	5.74%	2.85	5.00%	5.50%	0.24	0.32	0.49	9.75%
Mean:				**5.50%**	0.43	0.48		**9.88%**
Median:				**5.50%**	0.44	0.49		**9.88%**
Std Error:								**0.09%**

Compound Excess Returns (Long Horizon Risk Premia), 1926-2001

Period	Risk Premium
1926-1940	0.82%
1940-1955	14.38%
1955-1970	3.99%
1970-1985	1.51%
1985-2001	6.73%
Mean:	**5.49%**

Source: Derived from SBBI, Valuation Edition, 2002.

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES
DOCKET NO. NG02-011

TESTIMONY AND EXHIBITS OF MICHELE M. FARRIS
ON BEHALF OF THE COMMISSION STAFF
APRIL 2003

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Montana-Dakota Utilities
Docket No. NG02-011

Testimony of Michele M. Farris
On Behalf of Commission Staff

April 2003

1 **Q. Please state your name, business address and current position.**
2 A. My name is Michele M. Farris and my business address is Public Utilities
3 Commission, 500 East Capitol, Pierre, SD 57501. I am presently employed as a
4 Utility Analyst.
5 **Q. Please describe your educational background and experience.**
6 A. I received a Bachelor of Science degree in Mechanical Engineering from South
7 Dakota State University in May 1987. I received a Master of Science degree in
8 Civil Engineering from the University of Colorado in May 1994. I am a
9 registered Professional Engineer in the State of South Dakota. I commenced
10 employment with the Public Utilities Commission in January 1999.
11 **Q. Have you previously presented testimony before the Commission?**
12 A. Yes. I have presented testimony in three rate case filings, Docket NG01-010,
13 Docket NG99-002, and Docket NG98-011, requesting an increase in gas rates for
14 MidAmerican Energy Company, NorthWestern Public Service, and MidAmerican
15 Energy Company, respectively. In addition, I have presented testimony in the
16 following dockets: Docket GE00-002, request by The Dunham Company for a
17 master metering variance; Docket NG01-004, request by Floyd Nightingale for a
18 master metering variance; Dockets EL00-002, EL00-003, and EL00-009,
19 regarding approval of a departure from its fuel clause adjustment for Otter Tail
20 Power Company, Montana-Dakota Utilities Company, and NorthWestern Public
21 Service, respectively; and Docket TC99-005 regarding the sale of stock for Union
22 Telephone Company of Hartford and Armour Independent Telephone Co.,

1 including its wholly-owned subsidiary, Bridgewater-Canistota Independent
2 Telephone Co. to MJD Services Corp.
3 **Q. What is the purpose of your testimony in this proceeding?**
4 A. I shall express my opinion regarding adjustments to Montana-Dakota Utilities'
5 charitable contribution expenses, economic development expenses, industry and
6 association dues, chamber dues, advertising expenses, and rate case expense.
7 **Q. Did Montana-Dakota Utilities include charitable contribution expenses in the**
8 **South Dakota test year expenditures?**
9 A. No. Montana-Dakota Utilities has charged charitable contributions as a below the
10 line item for rate making purposes. No charitable contribution amounts were
11 included in South Dakota test year expenditures.
12 **Q. Based on your education and experience, what is your opinion in regard to**
13 **Montana-Dakota Utilities' claimed association dues?**
14 A. It is my opinion that an adjustment of ($33,453) be made to Montana-Dakota
15 Utilities' cost of service (see Exhibit__(MMF-1), Schedule 1). The organizational
16 dues, which were excluded, consist of payments to various Chambers of
17 Commerce and commercial clubs. Membership in these organizations is not
18 necessary for MDU's rendition of safe, adequate and reliable gas service in South
19 Dakota. Also, MDU should not be allowed to force ratepayers to contribute to
20 organizations with which they may not be in agreement.
21 The Utility Shareholders of South Dakota was established as an
22 independent organization in the state to represent the collective interests, rights
23 and concerns of utility investors in South Dakota. Membership in this
24 organization is not necessary for the rendition of safe, adequate and reliable gas
25 service in South Dakota. Therefore, membership dues should not be recovered
26 from ratepayers.
27 **Q. Based on your education and experience, what is your opinion regarding**
28 **institutional/promotional/goodwill advertising expenses?**
29 A. It is my opinion that an adjustment of ($39,197) be made to Montana-Dakota
30 Utilities' cost of service (see Exhibit__(MMF-1), Schedule 2). The advertising
31 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 $17,341 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 $1,929 for economic development expenses in account 912. I recommend this amount be disallowed. 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 $47,500 amortized over three years with a recurring level of expense of $2,065 per year. I accept the rate case expense as proposed. However, based on the duration of time elapsed since the last rate case in NG94-12, I recommend the expense be amortized over five years (see Exhibit __(MMF-1), Schedule 4.)

Q. Does that conclude your testimony?

Yes.

Montana-Dakota Utilities
South Dakota-Gas
Industry Association Dues
Test Year Ended June 30, 2002

	(a)	Company Pro Forma Per Books (b)	Staff Pro Forma Adjustments (c)
1	American Gas Association	$ 5,817	$ (1,882.00)
2	Rapid City Chamber of Commerce	$ 6,575	$ 6,575
3	Sturgis Chamber of Commerce	$ 574	$ 574
4	Deadwood Chamber of Commerce	$ 250	$ 250
5	Belle Fourche Chamber of Commerce	$ 499	$ 499
6	Lead Area Chamber of Commerce	$ 250	$ 250
7	Northern Hills Community	$ 250	$ 250
8	Whitewood Chamber of Commerce	$ 40	$ 40
9	Montana Coal Council	$ 200	$ 200
10	Spearfish Economic	$ 500	$ 500
11	Rapid City Area Economic	$ 3,500	$ 3,500
12	Spearfish Chamber of Commerce	$ 599	$ 599
13	UTC	$ 340	$ 340
14	NARUC	$ 179	$ -
15	Energy Safety Association	$ 1,060	$ -
16	Utility Shareholders of South Dakota	$ 19,403	$ 19,403
17	Other	$ 2,355	$ 2,355
	Total	$ 42,391	$ 33,453
18	Staff Pro Forma adjustment		$ (33,453)

Sources:

Column b, Lines 1-17: Statement H, Schedule H-1, Page 8 of 12
Column c, Line 9: Data Response 2-21
Column c, Line 13: Data Response 2-22
Column c, Line 16: Data Response 2-19
Column c, Line 17: Data Response 2-23

Montana-Dakota Utilities
South Dakota-Gas
Institutional/promotional/goodwill advertising
Test Year Ended June 30, 2002

	(a)	Advertising Expenses Per Books (b)	Company Pro Forma Adjustments (c)	Staff Pro Forma Adjustments (d)
1	Account 909 Informational Advertising	$ 15,773		
2	Account 913 Promotional Advertising	$ 21,856	$ 21,856	$ 21,856
3	Account 930.1Institutional Advertising	$ 17,341	$ 241	$ 17,341
	Total	$ 54,970	$ 22,097	$ 39,197
4	Company Pro Forma adjustment		$ (22,097)	
5	Staff Pro Forma adjustment to per books			$ (39,197)

Sources:

Column b and c, Lines 1, 2, 3 : Statement H, Schedule H-1, Page 12 of 12
Column d, Lines 2 and 3 : Statement H, Schedule H-1, Page 9 of 12

Montana-Dakota Utilities
South Dakota-Gas
Economic Development
Test Year Ended June 30, 2002

	(a)	Other O & M Expenses Per Books (b)	Staff Pro Forma Adjustments (c)
1	Sales	$ 40,636	
2	Account 912 Economic Development		$ 1,929
	Total	$ 40,636	$ 1,929
3	Staff Pro Forma adjustment to account 912		$ (1,929)

Sources:

Column b, Line 1: Statement H, Schedule H-1, Page 12 of 12
Column c, Line 2: Data Response 2-18

Montana-Dakota Utilities
South Dakota-Gas
Rate Case Expense
Test Year Ended June 30, 2002

(a)	Company Pro Forma Per Books (b)	Staff Pro Forma Adjustments (c)
1 Zinder (ROE)	$ 10,000	$ 10,000
2 Gerdes	$ 6,000	$ 6,000
3 Towers Perrin (FAS 106)	$ -	$ -
4 PUC FAS 106	$ -	$ -
5 PUC	$ 30,000	$ 30,000
6 Hearing	$ -	$ -
7 Other	$ 1,500	$ 1,500
Total	$ 47,500	$ 47,500
8 Three year amortization	$ 15,833	
9 Staff Adjustment (Five year amortization)		$ 9,500
10 Recurring level of expense	$ 2,065	$ 2,065
11 Company Pro Forma Rate Case Expense	$ 17,898	
12 Staff Pro Forma Adjustment		$ 11,565

Sources:

Column b and c, Lines 1 - 7, and 10: Statement H, Schedule H-1, Page 10 of 12

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA- DAKOTA UTILITIES
DOCKET NO. NG02-011

TESTIMONY & EXHIBITS OF DAVID A. JACOBSON
ON BEHALF OF THE COMMISSION STAFF
APRIL 2003

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES
DOCKET NO. NG02-011

TESTIMONY & EXHIBITS OF DAVID A. JACOBSON
ON BEHALF OF THE COMMISSION STAFF
APRIL 2003

1 **Q. What is your name and by whom are you employed?**
2 A. My name is David A. Jacobson and I am presently employed as a Utility Analyst
3 with the Commission Staff of the Public Utilities Commission (Commission). My
4 business address is Public Utilities Commission, State Capitol Building, Pierre,
5 South Dakota 57501.
6 **Q. Please describe your educational background and experience.**
7 A. I received a Bachelor of Science Degree in Business Administration majoring in
8 business management from the University of South Dakota in 1980. I
9 subsequently returned to the University in 1982 and completed major course
10 work in accounting. I have been with the Commission since May of 1984. I have
11 previously presented testimony in 14 general rate case applications and also in
12 numerous other docketed matters before the Commission.
13 **Q. What is the purpose of your testimony in this Docket?**
14 A. I shall present Staff's determination of working capital for Montana-Dakota
15 Utilities Co. (MDU or Company), and address Company proposed adjustments
16 regarding Labor and associated payroll taxes, benefits expense, Supplemental
17 Income Security Plan (SISP) and insurance expense. In addition I shall address
18 certain changes in tariffed rates, terms and conditions proposed by the
19 Company.

Q. Did MDU provide an analysis of its working capital requirements?

A. The Company provided 13-month 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 updating their balances to more recently available 13-month averages.

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. I first requested updated information from MDU and received the response that no updated information was available. I then referred to responses to data requests submitted by the Company in their most recent gas rate case, Docket NG94-012 where such updates were supplied. To the extent these expense leads were applicable, I utilized them in my analysis. Separately, the expense lead for labor was updated to reflect the current pay practices of the Company. Expense leads for taxes were used which reflect the applicable current statutory payment dates.

1 **Q. How did you compute MDU's revenue lag?**
2 A. I used a 20-day bill payment lag. South Dakota Administrative Rules provide that
3 a bill becomes delinquent after 20 days and thereafter a company can assess a
4 late payment charge. In collecting this charge, the company is compensated for
5 the costs of extending credit to their customers when payments are made later
6 than 20 days from billing. When adopting this approach, it is appropriate to
7 remove late payment fees from test year revenues for ratemaking purposes. Per
8 data request the Company indicated that late payment fees were not included in
9 test year results because the Company believes such revenues are not part of
10 the regulated cost of service. While this position is certainly debatable, in this
11 case they have appropriately not been included in test year revenues. For
12 processing days, the time between when meters are read and when a bill is
13 rendered, I utilized one day. The information from Docket NG94-012 did not
14 contain a calculation for processing days and, in any event, it has been my
15 observation that processing days for companies have decreased in the last
16 several years due to the application of new technologies. Processing days for the
17 other two local distribution companies regulated by the Commission have most
18 recently been determined to be less than one day. Lacking an actual current
19 study of this measure, I believe one day is appropriate and perhaps conservative
20 in this case. The details to my cash working capital calculation can be found on
21 Exhibit__(DAJ-1), Schedule 1.
22 **Q. Are there other sources of working capital available to the Company?**
23 A. Yes. Taxes collected by the Company and held until payment are included in
24 Exhibit__(DAJ-1), Schedule 2.
25 **Q. Has MDU proposed an adjustment to test year insurance expense?**
26 A. The Company proposed an adjustment increasing insurance expense based on
27 projections. It has long been the policy of the South Dakota Commission, and
28 appropriately so because of their speculative nature, to avoid the use of
29 projections for ratemaking purposes. Staff Witness Senger discusses this issue
30 further. It should be noted however that many of the Company's insurance

policies reflected in the initial filing expired in October and December of 2002. I requested updated insurance expense information and have proposed an adjustment incorporating that information.

Q. Have you reviewed the adjustment proposed by MDU for increasing labor expense over test year amounts?

A. The information provided by MDU supporting post test year labor increases consists primarily of an explanation of the budgeting and projection process and the results of that process. Exhibit__(DAJ-2), Schedule 3 is MDU's response to a Staff data request regarding the budgeting process. As the response indicates, 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.

Another problem with forecasting increased labor expense is the absence or lack of known productivity gains which result from salary increases. While in some cases, increases reflect only cost of living increases, the union contract supplied by MDU shows that as employees progress in their trades, they receive higher salaries but are also able to achieve higher job titles and theoretically able to perform more functions. Greater efficiency by employees should lead to decreased costs which are not reflected in the rate case.

As a result of the above problems, I, as the Commission has in the past, have relied on the known and measurable increases documented by the Company to adjust labor expense. The only documented change provided was the 3% union increase which took effect 5/1/02. For lack of better information,

1 this was applied to South Dakota based on the number of union employees
2 compared to total South Dakota employees. The results of this adjustment can
3 be seen on Exhibit__(DAJ-2), Schedule 2. The resulting change to payroll taxes
4 can also be found on that exhibit.
5 **Q. Did MDU propose an adjustment to employee benefits expense?**
6 A. Once again MDU provided a forecasted benefit increase. Through data requests,
7 I received updated actual benefits expense amounts for the 12 months ended
8 3/31/03 and have adjusted test year expenses by this known increase. The detail
9 for this adjustment can be found on Exhibit__(DAJ-2), Schedule 4.
10 **Q. Have you reviewed MDU's proposal to include the costs of the**
11 **Supplemental Income Security Plan (SISP) in the regulated cost of service?**
12 A. Yes. MDU is proposing to increase benefits expense by approximately $120,000
13 per year for South Dakota customers to include this program in its cost of
14 service. Briefly, the plan provides retirement benefits in addition to Social
15 Security, the Defined Benefit Pension Plan and MDU's 401(k) plan so that
16 income after retirement comes closer to equaling that made prior to retirement.
17 Current eligibility guidelines for the plan are that an individual should have a base
18 salary of at least $80,000 and be an officer or in a position of significant influence
19 and impact. The 2002 Proxy Statement of MDU Resources Group, Inc. states
20 there are 76 participants in the program. Responses to Staff data requests
21 explain that 26 of these 76 senior management personnel participating the SISP
22 are with MDU.
23 **Q. Do you have an opinion on whether this expense should be included for**
24 **recovery in rates from ratepayers?**
25 A. The other pension and retirement plans utilized by MDU are fully included in the
26 cost of service. Staff analyzed bonuses paid during the test year, the Key
27 Employee Stock Option Plan, the Executive Long Term Incentive Plan and other
28 plans. Although it was not quantifiable, these plans rely on stockholder
29 enrichment as a key measure in determining rewards, largely to upper level
30 management. It is apparent that stockholder welfare is a major concern of senior

1 management and, because Staff has allowed these programs to be funded, it
2 seems only reasonable to have the Stockholders of MDU Resources Group
3 continue to fund the SISP as they have in the past.
4 Another point to consider is that the SISP is available *only* to upper
5 management. It can well be argued that employees with smaller incomes at
6 retirement are more in need of having a greater portion of their salaries replaced
7 than retirees with larger ending salaries. While MDU acknowledges this matter,
8 this plan does not contribute to that end. Also, employees with larger salaries
9 may also have the ability to save more for retirement in plans outside of
10 Company sponsored plans than those who spend a larger share of their income
11 on meeting daily costs of living. Because of these issues, I would not allow SISP
12 costs to be recovered from South Dakota ratepayers.
13 **Q. Have you reviewed the changes MDU has proposed to their tariff in this**
14 **case and do you have any comments?**
15 A. Yes. MDU has proposed in this case to increase the penalty for failing to curtail
16 usage of gas during curtailment periods from $10 to $50. The Company states
17 this is necessary considering the recent instances of high gas costs which make
18 the penalty less effective than when gas prices were at lower levels. I would
19 agree with this assessment but would opine that $50 is too great an increase at
20 this time. Thirty dollars has been accepted by the Commission in the past and
21 would also be appropriate in this case. Also, MDU has stated that these penalties
22 shall be used to pay any pipeline penalties assessed because of the customer's
23 failure to curtail service. This treatment is appropriate but I would also have MDU
24 credit any collections of penalties in excess of the pipeline charges to the firm
25 customer's Purchased Gas Adjustment account. This practice is fair considering
26 the firm customers are at that point supplying the gas used by interruptible
27 customers. This practice is followed by other gas utilities regulated by the
28 Commission.

1 **Q. Are there other proposed changes to tariffed charges?**
2 A. MDU is proposing to increase the insufficient funds check charge from $10 to
3 $20. I would accept this change. The Company is also proposing to increase the
4 charge for reconnecting service in the event of disconnect for nonpayment from
5 $12 to $30. Because the cost support for this service was less than $30 and
6 because of the hardship many customers disconnected for nonpayment have in
7 paying prior amounts owed in addition to a reconnect charge, I would propose
8 the charge be set at $25.
9 MDU has also proposed to increase the deposit paid by customers for
10 having their meter tested more than once within a 12-month period. Customers
11 forfeit this deposit if their meter fails to be in error by 2% or more. MDU proposed
12 increasing the residential deposit from $10 to $40. ARSD 20:10:17:05 specifies
13 that this charge be $10 and cannot be increased. The Company has also
14 proposed increasing the non-residential charge for 425CFH or less meters from
15 $10 to $40, 426 CFH to 1000 CFH meters from $20 to $40 and over 1000 CFH
16 meters from $60 to $70. I would accept these proposed changes, with the
17 condition that in the case where a meter is replaced due to malfunction, a
18 customer be allowed one additional free meter test within 12 months, if requested
19 by the customer.
20 Regarding other proposed tariff changes, the Company has eliminated
21 Firm Transportation Service from the tariff. As no customers have been served
22 by this rate since its inception in 1988, I would accept this change. There are
23 numerous other tariff changes within the filing which have been discussed with
24 the Company and with which preliminary agreement has been made concerning
25 clarification or correction.
26 **Q. I have no further questions.**

Montana-Dakota Utilities Co.
South Dakota - Gas
Cash Working Capital
Test Year Ended 6/30/02

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	$ 21,351,949	$ -	$ 21,351,949	$ 58,498	41.2	$ 2,410,118
2	Labor Expense	3,594,005	49,736	3,643,741	9,983	19	189,677
3	Fringe Benefit	437,498	84,401	521,899	1,430	27.7	39,611
4	Insurance Expense	118,405	33,911	152,316	N/A		
5	Uncollectible Accounts Exp.	81,448	-	81,448	223	230.6	51,424
6	Regulatory Commission Exp.	59	11,565	11,624	N/A		
7	Other O & M Expense	2,031,324	(11,355)	2,019,969	5,534	16.4	90,758
8	Total O & M	27,614,688	168,258	27,782,946	75,668		2,690,830
9	Depreciation & Amortization	1,607,620	(128,047)	1,479,573	4,054	0	-
10	Deferred Income Taxes	(107,226)	-	(107,226)	(294)	0	-
11	Ad Valorem Tax	387,047	14,775	401,822	1,101	395.25	435,170
12	Payroll - FICA	250,469	4,486	254,955	699	19	13,281
13	Payroll - FUTA	3,933	65	3,998	11	47	517
14	Payroll - SUTA	5,894	80	5,974	16	47	752
15	S D Gross Receipts Tax	62,122	(14,539)	47,583	130	334	43,420
16	Federal Income Tax	546,059	(117,932)	428,127	1,173	37	43,401
17	Interest on Long Term Debt	690,972	(58,797)	632,175	1,732	91.3	158,132
18	Preferred Stock Dividends			38,938	106	45.6	4,834
19	Total	$ 31,061,578	$ (131,651)	$ 30,968,865	$ 84,396	40.17	$ 3,390,337.00

20	Revenue Lag Days	36.21
21	Expense Lead Days	40.17
22	Net Days	(3.96)
23	Expense per Day	84,396
24	Cash Working Capital	(334,208)

Sources :

Column (b)
line 1: Statement H, page 1 of 3
line 2: Statement H, Schedule H-1, page 4 of 12
line 3: Statement H, Schedule H-1, page 5 of 12
line 4: Statement H, Schedule H-1, page 6 of 12
line 5: Statement H, page 2 of 3
line6: Statement H, Schedule H-1, page 10 of 12
line 7: line 9 minus lines 1 - 7
line 8: Statement H, page 3 of 3
line 9: Statement J, page 1 of 3
line 10:Statement K, page 9 of 12
line 11: Statement L, page 1
lines 12 - 15: Statement L, page 1
line 16: Statement K, page 4 of 12
line 17: Statement K, page 4 of 12
line 20: Staff Workpaper reflects 1 day processing and 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 19
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 5, Column b, line 5
line 18: KAS-1, Sch 1, col b, line 1 * BLC-1, Sch 1, col d, line 2

Column (e)
line 4: Separately included in rate base
line 6: Separately included in rate base

Column (f)
lines 1 , 3 -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 June 1 payment date
line 16: Staff workpaper
lines 17 and 18: NG94-012 Data Response 1-6

Montana-Dakota Utilities Co.
South Dakota - Gas
Tax Collections Available
Test Year Ended 6-30-02

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	$ 250,469	$ 4,486	$ 254,955.00	$ 698.51	19	$ 13,271.63
2	Federal Witholding	407,368	5,637	413,005.00	$ 1,131.52	19	$ 21,498.89
3	South Dakota Sales Tax	1,537,115	9,153.16	1,546,268.16	$ 4,236.35	9.61	$ 40,711.33
4	Total						$ 75,481.85

Sources:

Column (b), line 1: Statement L, page 1 of 1, and Data Response 4-32
Column (b), line 2: Data Request 4-33 allocated to Black Hills gas by 06/02 customer count
Column (b), line 3: Data Request 3-46 and 4/15/03 email from R. Mulkern
Column (c), line 1: KAS-1, Schedule 1, column 1, line 20
Column (c), line 2: Column b, line 2 divided by KAS-1, Schedule 2, column b, line 9 times KAS-1, Schedule 2, column c, line 9
Column (c), line 3: Sum of (KAS-1, Schedule 2, column c, line 5 and KAS-1, Schedule 2, column e, line 5) * 0.04
Column (f), line 1: Bi-weekly payroll plus 12 day lag
Column (f), line 2: Bi-weekly lines1-3: Exhibit__(RAA-1), Schedule 1, page 2 of 2
Column (f), line 3:[(365/12)/2] + 30.4 - 36 (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 06-30-02

	(a) Item	(b) Per Books	(c) Updated	(d) Increase / (Decrease)
1	Materials and Supplies	$247,865	$254,074	$6,209
2	Prepaid Insurance	51,443	47,947	($3,496)
3	Unamortized FAS 106	174,494	165,241	($9,253)
4	Customer Advances for Costruction	85,591	90,102	$4,511

Sources:
Column (b)
line 1: Statement F, Schedule F-1, page 2 of 5, average of per books end of month balances
line 2: Statement F, Schedule F-1, page 3 of 5, average of per books end of month balances
line 3: Statement F, Schedule F-1, page 4 of 5, average of per books end of month balances
line 4: Statement F, Schedule F-1, page 5 of 5, average of per books end of month balances

Column (c)
lines 1, 2 and 4: Data Request 2-25, 13 month average of end of month balances ending 01/03
line 3: Statement F, Schedule F-1, page 4 of 5, 13 month average of end of month balances ending 01/03

Montana-Dakota Utilities Co.
South Dakota - Gas
Insurance Expense
Test Year Ending 6-30-02

Exhibit__(DAJ-2)
Schedule 1
Page 1

1	Test Year Insurance Expense	$118,405
2	Actual Insurance Expense Year Ended 2/28/03	152,316
3	Increase in Insurance Expense	$33,911

Sources:
line 1: Data Request 1-2, Attachment A, Statement H, page 32
line 2: Data Request 3-45, Attachment A, page 1 of 1

Montana-Dakota Utilities Co.
South Dakota - Gas
Labor and Payroll Tax Expense
Test Year Ended 6-30-02

	(a) Item	(b) Amount
1	South Dakota Test Year Labor	$3,594,005
2	South Dakota Labor 6/01 - 4/02 (Union Increase Effective 5/02)	3,008,713
3	SD 6/01 - 4/02 Labor Expenses Subject To Increase Per Union Contract	
4	Straight Time	2,369,983
5	Premium Time	128,421
6	Vacation	342,210
7	Total	$2,840,614
8	South Dakota Union Employees / Total South Dakota Employees	0.58362369337
9	Labor Expense Subject To Union Contract Increase	$1,657,850
10	SD 6/01 - 4/02 Union Labor Increased 3%	1,707,586
11	Increase To South Dakota Labor Expense	$49,736
	Payroll Tax Increase	
12	FICA @ 9.02%	$4,486
13	FUTA @ .13%	$65
14	SUTA @ .16%	$80

Sources:
Column (b)
line 1: Statement H, Schedule H-1, page 4 of 12
line 2, 4, 5, & 6: Data Response 3-14
line 8: Data Response 3-10, average June 2001 through June 2002
line 12: FICA tax rate
line 13: FUTA tax rate
line 14: SUTA tax rate

MONTANA-DAKOTA UTILITIES CO.
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF
SECOND DATA REQUEST
DATED MARCH 5, 2003
DOCKET NO. NG02-011

Request No. 2-29 Labor

Provide a detailed description of the budgeting process used to determine future labor expense including the basis for budgeted amounts, the number of persons involved in the budgeting process, the positions of those involved in the process from initiation to final approval and the position of those giving final approval.

Response:

The administration of the annual responsibility budget process and systems resides with the Financial Reporting and Planning department under the direct supervision of the Controller.

The operating and maintenance responsibility budget is prepared by individual responsibility center (i.e. department managers) on a monthly basis for one year and is developed by resource or cost code (i.e. expenses such as payroll, benefits, contract services, materials, company auto and work equipment usage, etc.). Each manager is responsible to determine the costs necessary to operate and manage their respective area of responsibility and systems to provide safe and reliable service to the customers they serve. Managers have the responsibility to enter their budgets into the budgeting system.

The responsibility budget request is distributed to Montana-Dakota department managers at the end of July each year for completion at the end of August. Payroll increases and other cost index guidelines, excluding employee benefits, are set forth in the request by the Financial Reporting and Planning Department as approved by Senior Management.

Future labor expense increases that are included in the operating budget are approved by the Senior Management Policy Committee and reflect a combination of EEI/AGA (industry), Towers Perrin (actuarial) and regional salary studies, as well as the effects of union contracts. Prior to contract negotiations, an extensive market research study on labor and benefits is conducted and most recently completed in 2002. Employee benefits are derived from projections obtained from actuarial estimate reports as well as projected health care cost increases.

The responsibility budget resides on the general ledger/financial accounting software systems. The budgets are then compiled and consolidated and various budget analyses are prepared for senior management's review. Upon consolidation the O&M responsibility budget is reviewed and approved by each respective Vice President for the area under their supervision. After the Vice President review, the operating budget is revised for their changes and then submitted for approval to the President of

Response No. 2-29 (cont.)

Montana-Dakota Utilities Co. (Montana-Dakota). Upon that approval the budget is submitted for inclusion in the five-year financial forecast and approved by the CEO of Montana-Dakota and the Senior Management of MDU Resources Group, Inc. Once approved at that level the financial forecast is distributed to the Board of Directors for their approval at the February Board Meeting.

Montana-Dakota Utilities Co.
South Dakota Gas
Benefits Expense
Test Year Ended 6-30-02

	(a) Item	(b) Test Year Per Books Benefits Expense	(c) Benefits Expense Update Year Ended 3/31/03	(d) Increase/(Decrease)
1	Medical/Dental	$378,120	$365,261	($12,859)
2	Pension	(273,717)	(232,786)	40,931
3	Post Retirement	218,015	249,086	31,071
4	401-K	94,980	101,632	6,652
5	Workers Compensation	20,100	38,706	18,606
6	Total	$437,498	$521,899	$84,401

Sources:
Column (b)
lines 1-5: Statement H, Schedule H-1, page 5 of 12

Column (c)
lines 1-5: 4/21/03 email from T. Aberle

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG02-011

TESTIMONY & EXHIBITS OF KEITH A. SENGER
ON BEHALF OF THE COMMISSION STAFF
APRIL 2003

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG02-011

TESTIMONY & EXHIBITS OF KEITH A. SENGER
ON BEHALF OF THE COMMISSION STAFF
APRIL 2003

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 Docket NG98-011, NG99-002, NG01-010 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 NG02-011?

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 will explain Staff's approach to measuring MDU's South Dakota gas revenue requirement. I have prepared exhibits that summarize Staff's case and I will also express opinions on the following specific revenue requirement issues:

<u>Rate Base:</u>

1. Historic Test Year amounts
2. Plant Additions & Retirements
3. Accumulated Deferred Investment Tax Credit

<u>Operating Income:</u>

1. Historic Test Year Amounts
2. Depreciation Expense – Plant Additions and Retirements
3. Ad Valorem Taxes
4. Postage Expense
5. Inflation Adjustment for Other O&M Expense
6. Gain on the Sale of Office Building
7. Interest Synchronization
8. Gross Receipt Tax Adjustment

Q. What is MDU requesting in docket NG02-011?

A. MDU is requesting a projected revenue requirement of approximately $39,508,000.[1] This includes a requested rate of return on common equity of 12.0%.[2] More importantly, this represents a rate increase of approximately $2,174,000[3] to its current South Dakota gas service rates that were established in Commission Docket NG94-012. MDU describes this as a 5.8% overall increase.[4] However, MDU includes 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 is not a component of base rates, it is more appropriate to measure the general rate increase excluding the purchased gas costs. Accordingly, MDU is seeking a 21.2% increase in its existing base rate revenues.

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. According to Company Witness R. A. Mulkern, MDU's "revenue requirement is based on a *projected* average 2003 test year."[5] [Emphasis added] Generally speaking, MDU starts with a twelve-month historic test year ending 6/30/02. MDU then forecasts the cost of service to attain a 2002 projected test year,[6] and then again forecasts to ultimately arrive at a 2003 projected test year.[7] MDU uses this 2003 projected test year to measure the cost of service.

Q. What are MDU's forecasts and projections based on?

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[1] MDU Exhibit No.___(RAM-1), page 3 of 3.
[2] Testimony of J. S. Gaske, page 35, lines 5 – 11 and Statement G, page 3 of 3.
[3] Testimony of Company President, C. W. Fox, page 6, lines 20 - 21, Testimony of R. A. Mulkern, page 10, lines 9 - 15, and MDU Exhibit No.___(RAM-1), page 3 of 3.
[4] Statement O, page 1 of 1 and Testimony of Company President, C. W. Fox, page 6, lines 1 – 9.
[5] Testimony of R. A. Mulkern, page 3, lines 14 – 15.
[6] Twelve-month period ending 12/31/02.
[7] Twelve-month period ending 12/31/03.

A. According to MDU, the 2003 projected test year is based on projected customer increases, [8] projected sales volumes, [9] budgeted amounts, [10] projected increases[11] and capital budget items. [12]

Q. Are you indicating that all of MDU's adjustments are based on forecasts, projections and budgets?

A. No. MDU proposes some adjustments based on sound "known and measurable" principles, but for the most part, they are based on projections, forecasts and budgets.

Q. Do you support MDU's use of a 2003 projected test year?

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 are speculative and cannot be verified for accuracy. Staff believes the possibility for incorrect projections are undesirable for ratemaking purposes. Therefore, Staff opposes the use of partially or fully forecasted or projected test years.

Q. Are you familiar with Administrative Rule of South Dakota (ARSD) 20:10:13:44?

A. Yes. Administrative Rule of South Dakota (ARSD) 20:10:13:44 states:

> *The statement of the cost of service shall contain an analysis of system costs as reflected on the filing utility's books for a test period consisting of 12 months of* ***actual*** *experience ending no earlier than 6 months* ***before*** *the date of filing of the data required by §§ 20:10:13:40 and 20:10:13:43 unless good cause for extension is shown.*
>
> ...

[8] Testimony of R. A. Mulkern, page 4, line 12.
[9] Testimony of R. A. Mulkern, page 5, line 7.
[10] Testimony of R. A. Mulkern, page 6, line 5.
[11] Testimony of R. A. Mulkern, page 6, line 5.
[12] Testimony of R. A. Mulkern, page 8, line 22 and page 9, line 2.

*Proposed adjustments to book costs shall be shown separately and shall be fully supported, including schedules showing their derivation, where appropriate. However, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are **known** with reasonable certainty and **measurable** with reasonable accuracy at the time of the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period. [Emphases added]*

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 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 all 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.

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 $2,174,000 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 $249,236[13] 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 9.75%.[14]

Q. Why such a large difference between MDU's revenue deficiency and Staff's revenue deficiency?

A. The differences are due to a whole host of reasons. However, generally speaking these differences can be grouped into three major categories: rate base differences, operating income differences and rate of return differences.

Q. Please explain the differences.

A. First of all, MDU's case projects the June 30, 2002, average rate base to increase by almost 20% in 18 months. Staff's case, as adjusted for known and measurable changes, increases the June 30, 2002, rate base by only 9%. Additionally, MDU projects the twelve-month operating income ending June 30, 2002, to fall by 62% in 18 months. While Staff's case, as adjusted for known and measurable changes, actually increases the twelve-month test year operating income by 16%. This increase is mostly attributed to MDU's excessive depreciation rates and failure to recognize consolidated tax savings.[15] Finally, MDU is requesting a 12.0% return on common equity while Staff is proposing a 9.75% return on common equity.

[13] Staff Exhibit___(KAS-1), Schedule 1, column b, line 10.
[14] Testimony of Basil L. Copeland Jr. and Staff Exhibit___(BLC-1), Schedule 1, column c, line 3.
[15] Testimony of Robert G. Towers.

Q. Why the large difference?

A. As I stated earlier MDU's case uses a projected test year while Staff's case uses a historic test year adjusted for known and measurable changes. The use of a projected test year allows the company to name the cost of service it desires.

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 6/30/02. MDU then forecasts the cost of service to attain a 2002 projected test year, and then again forecasts based on a projected 2002 test year to ultimately arrive at a 2003 projected test year. This 2003 projected test year is used by MDU for measuring the cost of service. [16]

Q. What did you use as a test year for Staff's case?

A. I used a historic test year ending 6/30/02. This is sometimes referred to as "6/30/02 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

[16] Statement M, pages 3 and 4 of 5.

(6/30/01) and the ending period (6/30/02) account balances. My average rate base amounts were the result of a twelve-month midmonth average using the beginning and ending account balances for all twelve months. This is often referred to as (or a form of) a thirteen-month average.

Q. Please explain a thirteen-month average.

A. A thirteen-month average, in its simplest form, is derived from averaging the ending balances from thirteen consecutive months. A thirteen-month average captures the entire year's activity. In Staff's case, we used a test year starting July 1, 2001, and ending June 30, 2002. A thirteen-month average balance for that test year uses the ending balances of 6/30/01, 6/30/02 and every month in-between. Since the 6/30/01 ending balance is also the 7/01/01 beginning balance, Staff has captured the entire year's activity.

Q. Please explain the twelve-month midmonth average that you used.

A. As stated earlier, the twelve-month midmonth average I used is a form of a thirteen-month average in that, it too, is derived from taking the ending balance from thirteen months. It is calculated by averaging each month's beginning and ending balances to obtain a midmonth average and then averaging the individual twelve-month averages to obtain the twelve-month midmonth average.

Q. Why did you use a twelve-month midmonth average instead of the simplified thirteen-month average described earlier?

A. I used the twelve-month midmonth average because MDU provided the midmonth averages for plant in service.[17] However, MDU did not use these midmonth averages for rate base nor did they provide the midmonth average for the remaining rate base items. As stated earlier, MDU used an average derived from the beginning period (6/30/01) and ending period (6/30/02) balances.

Q. Why did you use this twelve-month midmonth average instead of MDU's average?

[17] Statement D, Schedule D-3.

1 A. Historically the Commission has used thirteen-month averages, or various forms like a
2 twelve-month midmonth average, for rate base items because it better reflects the
3 matching of costs, investments and revenues that I spoke of earlier.
4
5 **Q. Please explain.**
6 A. Under MDU's method, a plant item placed in service during the last month of a test year
7 is inappropriately weighted as if it has been in service for six months. Since revenue is
8 recorded as an accumulation of a year's activity, the books and records for that year
9 would only reflect one month's worth of revenue generated from that plant, thus creating
10 a mismatch. A thirteen-month average would weight that plant appropriately to better
11 reflect the matching principal.
12
13 **Q. Were you able to use a twelve-month midmonth average for all rate base items?**
14 A. No. I was unable to use a twelve-month midmonth average for accumulated
15 depreciation.
16
17 **Q. Why not?**
18 A. MDU did not provide the information necessary to make the calculation. On April 7,
19 2003, Staff submitted a request for the test year midmonth accumulated depreciation
20 averages.[18] The Company's response to this request was due April 14, 2002.
21 Discussions with a Company representative on 4/18/03 revealed that MDU, because of
22 staffing issues, was unable to provide that information to Staff before it's testimony was
23 due on April 23, 2003.[19]
24
25 **Q. What did you do?**
26 A. I used MDU's average accumulated depreciation.
27
28 **Q. What effect would this have on rate base and the revenue requirement?**
29 A. Without the thirteen-month averages I am unable to determine the amount of any
30 effects. However, given some of the circumstances in this case, I believe, that using the
31 thirteen-month average plant and MDU's average accumulated depreciation would
32 cause a decrease in rate base; thus a decrease in the revenue requirement.

[18] Staff request DR4-13.
[19] April 18, 2003, telephone discussion with Tamie Aberle.

Q. Please explain.

A. Staff's thirteen-month average gas plant in service balance was approximately $1,000,000 less than MDU's calculated average,[20] indicating there was a large plant increase at the end of the test year. Barring any large retirement of fully, or almost fully, depreciated plant at the beginning of the year, MDU's calculated average accumulated depreciation balance should also be higher than Staff's thirteen-month average. Since accumulated depreciation is a reduction in plant to achieve net plant in service, the use of Staff's lower plant in service amount and MDU's higher accumulated depreciation amount would result in a lower net plant in service; thus reducing rate base and the revenue requirement.

Q. Are you saying MDU's failure to provide the information necessary for Staff to make its adjustment, could actually lower Staff's revenue requirement?

A. Yes. Barring any large retirements of fully, or almost fully, depreciated plant at the beginning of the year or other activities that would have a counter effect, I believe it has lowered Staff's revenue requirement. However, I do not believe it is appropriate to handle it this way because we are mismatching plant in service and accumulated depreciation. If MDU offered a twelve-month midmonth average for accumulated depreciation, I would accept the adjustment no matter what the effect on the revenue requirement.

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.[21]

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

[20] Compare Staff Exhibit___(KAS-2) Schedule 2, column b, line 5 ($37,919,229) to Statement M, page 2 of 5, South Dakota - Gas Plant in Service ($38,932,377).
[21] Company response to DR4-19 and 4-22.

based on company revenue. A summary can be found on Staff Exhibit___(KAS-2) Schedule 3

PLANT ADJUSTMENT

Q. Is MDU proposing adjustments to plant?

A. Yes. MDU proposes adjustments to plant in service for budgeted and projected plant additions and retirements through 12/31/03.[22] Additionally, MDU is proposing to adjust the corresponding accumulated depreciation and depreciation expense for those projected plant additions and retirements.[23]

Q. Do you agree with MDU's method of adjusting plant?

A. No. MDU's plant adjustments are based on budgeted and/or projected projects. Thus, the plant adjustments do not conform to the known and measurable criteria.

Q. Are you proposing a known and measurable plant adjustments to the historic test year?

A. Yes. Originally I was going to propose known and measurable adjustments to annualize the major non-revenue producing plant additions and retirements that were placed in service and were used and useful or retired during the test year ending 6/30/02. I was also going to propose to annualize the major non-revenue producing plant additions or retirements that were placed in service and were used and useful or retired post test year (from the end of the test year to current).

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 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 producing plant does not produce any new revenue, cost savings or changes in cash flow.

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[22] Statement D.
[23] Statements E and J.

Q. Why adjust only non-revenue producing plant additions and retirements?

A. Non-revenue producing plant additions and retirements 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."

Q. Why annualize only the test year and completed post test year plant additions and retirements?

A They are the only plant adjustments that are known and measurable.

Q. Did you complete the proposed adjustments?

A. No. I was unable to perform these adjustments because MDU did not provide the requested information[24] due to staffing issues.[25]

Q. What is the effect of not performing these adjustments?

A. Annualizing plant additions increases rate base and depreciation expense which would increase the revenue requirement. Therefore, by not completing these adjustments, rate base and depreciation expense are not increased, thus there is no increase to the revenue requirement. Annualizing plant retirements would have the opposite effect, but to a lesser degree, because most plant that is retired is fully, or almost fully, depreciated, thus minimizing the effect.

Q. Are you saying MDU's failure to provide the information necessary for you to make your adjustment could actually lower Staff's revenue requirement?

A. Yes. I believe the overall effect of not performing this adjustment results in a decrease in Staff's revenue requirement.

Q. Were you able to annualize any plant additions?

A. Yes. Based on the information that was provided, and by making a number of assumptions, I was able to calculate a rough adjustment to annualize the new Rapid City office building. This adjustment is summarized on Staff Exhibit___(KAS-2), Schedule 5.

[24] Staff request DR4-28, 29, 30 and 31.
[25] April 18, 2003, telephone discussion with Tamie Aberle.

1 **Q Please explain your adjustment and assumptions.**

2 A. First I noted a large increase in the general plant Land (acct 389) and Structures (acct
3 390) accounts in the month of March.[26] I assumed these increases to be the addition of
4 the new Rapid City office building and the cost of the cleanup remediation of the related
5 land.[27] Second I noted the Completed Construction not Classified had a large increase
6 in January and a large decrease in March.[28] I assumed this too was the new Rapid City
7 office building and related land. Third I noted that the old Rapid City office building
8 (Kansas Street office building) was retired (sold) in March of 2002.[29] To determine the
9 amount for my adjustment, I annualized the 6/30/02 land and structure account
10 balances, including the calculated accumulated depreciation and depreciation expense.
11 I then subtracted the per books plant balance, including the related accumulated
12 depreciation and depreciation expense, and what I believe to be the associated amounts
13 included in Completed Construction not Classified. Since I am annualizing the year end
14 balance, the adjustment should capture both the new office building addition and the old
15 office building retirement.
16
17 **Q. Do you have any concerns regarding your adjustment?**

18 A. Yes. First of all, I believe annualizing non-revenue producing plant is an appropriate
19 known and measurable adjustment, however, it should be performed with information
20 that is more accurate than what MDU has made available to Staff. The adjustment is
21 made based on some assumptions and incomplete information which could lead to
22 inaccuracies.
23
24 **Q. Why did you make such an adjustment if you have reservations about its**
25 **accuracy?**

26 A. Again, I believe annualizing the addition of the new building and the retirement of the old
27 building is an appropriate known and measurable adjustment. Thus such an adjustment
28 needs to be made. I would ask that MDU provide the requested information and provide
29 a more accurate adjustment with supporting documentation. I would accept a revised
30 adjustment by MDU as long as 1) the plant additions being annualized are non-revenue

[26] Statement D, Schedule D, page 1 of 2, General Plant, account 389 – Land and account 290 - Structures and Improvements.
[27] Company response to DR3-50 and 3-51.
[28] Company response to DR4-15.
[29] Statement D, Schedule D-2, page 1 of 6.

producing, 2) the adjustment is netted for any associated balances in the "completed construction not classified" account, and 3) the adjustment is for plant appropriately allocated to the Black Hills gas utility operations.

Q. Do you have any other concerns about plant additions and retirements?

A. Yes, I have two. First, the Company has capitalized the redemption gas plant costs at the Steele Avenue property in a land account. I'm not sure this is the appropriate accounting for such a transaction. Second, I was unable to find where the Company has retired the old buildings that were demolished on the Steel Avenue property. I would ask the Company to address both of these issues.

AD VALOREM TAXES

Q. Did the Company propose an adjustment to Ad Valorem Taxes?

A. Yes. The Company is projecting Ad Valorem Taxes based on the 2003 projected plant balances discussed above. More specifically, MDU calculated the effective Ad Valorem tax rate by function based on 12/31/01 average plant balances and the actual Ad Valorem taxes paid during 2001.[30] MDU then multiples the 2003 projected plant balances by this functional specific effective tax rate to obtain the 2003 projected Ad Valorem tax.[31]

Q. Do you agree with this adjustment?

A. No. Again, the whole adjustment is based on the 2003 projected plant balances and are not known and measurable.

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 annualized additions and retirements to plant multiplied by a calculated effective Ad Valorem tax rate. However, because MDU did not provide the information for Staff's plant adjustment, an Ad Valorem adjustment could only be completed only for the plant additions noted above. This adjustment is summarized on Staff Exhibit___(KAS-2), Schedule 5.

[30] Statement L, Schedule L-1, page 2 of 3.
[31] Statement L, Schedule L-1, page 1 of 3.

Q. What is the effect of not being able to complete this adjustment?

A. An Ad Valorem adjustment would increase Ad Valorem tax expense for the net increase of the plant adjustments. I believe the net effect of Staff's originally proposed known and measurable plant adjustment would have resulted in an overall increase in plant. Accordingly, I believe Staff's increase in Ad Valorem tax would have been higher, causing a further increase in Staff's revenue requirement had MDU provided the plant information. Again, I would not oppose such an amendment to this adjustment if MDU provides the plant information required, as long as the effective tax rate used is a South Dakota effective Ad Valorem tax rate, not a composite effective rate of other states.

ACCUMULATED DEFERRED INVESTMENT TAX CREDIT

Q. What is accumulated deferred investment tax credit (ADITC)?

A. According to the FERC Uniform System of Accounts, the account entitled "accumulated deferred investment tax credits" includes all investment tax credits deferred by the company which follow "deferral accounting" rather than recognizing the benefits of the tax credits in the income statement.[32] ADITC would be a deduction to rate base.

Q. How is MDU accounting for the ADITC?

A. It is my understanding that MDU is amortizing the ADITC over 20 years.[33]

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.[34] Staff's adjustment, as found on Staff Exhibit ___ (KAS-2), Schedule 4, 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 26.4 years instead of 20 years. This adjustment conforms with Staff's previous treatment of MDU's ADITC.

[32] 18 CFR part 201.255.
[33] Company response to DR1-20 and DR3-1.
[34] Company response to DR1-20 and DR3-1.

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.

POSTAGE EXPENSE

Q. Did you review MDU's postage expense increase?

A. Yes.

Q. Please explain this increase?

A. MDU's postage increase projects a 7.5% increase in MDU's twelve-month ending 6/30/02 postage expense.[35] At first glance this appears to be a modest and conservative increase. According to United States Postal Service (USPS) information provided by MDU, "First-Class Mail rates would increase an average of 8.2%. The single-piece 1-ounce First-Class Mail rate would increase from $0.34 to $0.37..." [36] Since the single-piece 1-ounce First-Class Mail rate increased over 8.8%, it can be assumed that other mail rates, including presorted first class mail which MDU uses for its monthly bills, the bulk of its mailings, increased something less than 8.2% in order for the average rate increase to be 8.2%; thus, justifying the 7.5% increase. However, information downloaded from the USPS website indicates that the 6/30/02 USPS average rate increase for First-Class Mail was 7.9% [37] not 8.2%. Additionally, the Company support that was provided suggests that the 7.5% increase was also based on projected increases in mail volume based on projected customer increases (increased bills) and an increase in disconnect notices.[38]

Q. What are you proposing in regard to the postage increase?

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[35] Statement H, Schedule H-1, page 7 of 9.
[36] Company response to DR1-2, support for Statement H, page 46, USPS information publication.
[37] KAS-1, Schedule 4, page 2 of 4, USPS information publication.
[38] Company response to DR1-2, support for Statement H, page 43.

A. I am proposing a known and measurable adjustment that increases postage expense by the rate increase. This adjustment eliminates the projected increases in mail volume and increases in disconnect notices and uses the 7.9% average First-Class Mail rate increase versus the 8.2%. My adjustment is summarized on Staff Exhibit___(KAS-1), Schedule 4.

INFLATION ADJUSTMENT FOR OTHER O&M EXPENSE

Q. Has MDU proposed an inflation adjustment?

A. Yes.

Q. Have you reviewed MDU's Adjustment?

A. Yes I have.

Q. Please explain MDU's adjustment.

A. MDU's inflation adjustment increases Other Operating & Maintenance (O&M) expenses "not specifically identifiable or calculated"[39] by a three-year average inflation rate using the Consumer Price Index for All Urban Consumers – (CPI-U), U.S. City Average, All Items (1982-84=100).[40] More specifically, MDU increases 6/30/02 Other O&M expense by 2.68% to arrive at 2002 projected levels. The 2002 projected levels are then again increased by 2.68% to arrive at 2003 projected levels. The 2.68% increase used is a three-year average increase of the period starting July 1999 and ending June 2002.[41]

Q. Do you agree with MDU's inflation adjustment?

A. I do not oppose an inflation adjustment because of a South Dakota Supreme Court decision in Otter Tail Power Company Docket F-3052 appeal.[42] This decision directed the Commission to accept such an adjustment. However, I do not agree with MDU's method for the adjustment because its adjustment projects future inflation to be that of the historic three-year average inflation rate.

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[39] Testimony of R. A. Mulkern, page 7 lines 9 – 10.
[40] Company response to DR1-2, support documentation for statement H, pages 57 – 58.
[41] Statement H, Schedule H-1, page 11 of 12 and Company response to DR1-2, support documentation for statement H, page 56.
[42] South Dakota Public Utilities Commission v. Otter Tail Power Company, 291 N.W.2d 291 (S.D. 1980).

Q. Do you believe the MDU adjustment meets the known and measurable criteria?

A. No. Future inflationary rates are definitely not known and certainly not measurable.

Q. What are you proposing for an inflation adjustment?

B. I am proposing an adjustment that applies one-half the actual inflation rate experienced during the historic test year to the 6/30/02 Other O&M expenses not otherwise adjusted. This procedure annualizes the historic test year Other O&M to the test year-end levels. I believe this adjustment alone satisfies the Supreme Court ruling. However, I am also proposing to further adjust this annualized amount by the most recent available post test year inflation rate. These adjustments are summarized on Staff Exhibit___(KAS-1), Schedule 6.

GAIN ON THE SALE OF OFFICE BUILDING

Q. Did MDU record a gain on the sale of the old Rapid City office building located on Kansas City Street?

A. Yes. The Company has recorded a gain of $260,280 in account 421.1 (Gain on the Disposition of Property) from the sale of that property.[43]

Q. What rate making treatment do you propose for this gain?

A. This office building has previously been a rate base item supported by ratepayers. Therefore, I suggest the gain be treated as a reduction in the cost of service amortized over five years. My adjustment is summarized on Staff Exhibit___(KAS-1), Schedule 8.

INTEREST SYNCHRONIZATION

Q. Is MDU proposing an adjustment for Interest Synchronization?

A. Yes. However, once again MDU is basing the adjustment on a projected rate base.[44]

[43] Company response to DR3-53.
[44] Statement K, page 6 of 12.

Q. What are your proposing?

A. I am proposing an interest synchronization adjustment based on the historic test year rate base as adjusted by Staff for known and measurable changes.

Q. Please explain why such an adjustment is necessary.

A. This adjustment is necessary to synchronize the tax deduction for interest on debt with the adjusted rate base and weighted cost of long-term debt. Staff's Interest Synchronization adjustment can be found on Staff Exhibit___(KAS-1), Schedule 5.

GROSS RECEIPTS TAX

Q. Is MDU proposing any adjustments to the South Dakota Gross Receipts Tax (GRT) for its adjustments to revenues?

A. MDU adjusted GRT for the revenue deficiency.[45] However, I see no other GRT adjustments.

Q. Have you prepared any GRT adjustments?

A. Yes. Staff Exhibit ___(KAS-1), Schedule 3, line 23 calculates the GRT tax effect of all of Staff proforma 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 7 adjusts the test year GRT expense to match MDU's reported test year revenues.

Q. Does this conclude your testimony?

A. Yes.

[45] Statement M, page 5 of 5 (Taxes Other Than Income).

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Revenue Requirement
Adjusted Test Year Ended June 30, 2002

Line	Description	Staff Proposed South Dakota Adjusted Test Year Gas	MDU Proposed South Dakota - Gas Projected 2003 Test Year	Difference
	(a)	(b)	(c)	(d)
1	Average Rate Base	$ 15,799,043	$ 17,793,768	$ (1,994,725)
2	Adjusted Test Year Operating Income	1,298,545	423,632	874,913
3	Overall Rate of Return	8.219%	2.381%	
4	Staff Recommended Rate of Return	9.243%	10.303%	
5	Required Operating Income	1,460,306	1,833,292	(372,986)
6	Income Deficiency (Excess)	161,761	1,409,660	(1,247,899)
7	Gross Revenue Conversion Factor	1.53846	1.53846	
8	Revenue Deficiency (Excess)	248,863	2,168,708	(1,919,845)
9	Gross Receipts Tax (at 0.0015)	373	3,253	(2,880)
10	**Total Revenue Deficiency (Excess)**	**249,236**	**2,171,961**	(1,922,725)
11	Adjusted Test Year Revenue	31,474,298	37,334,019	(5,859,721)
12	**Revenue Requirement**	**$ 31,723,534**	**$ 39,505,980**	$ (7,782,446)

SOURCES:
Column b, line 1: KAS-2, schedule 1, page 1, column d, line 31
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 * 0.0015
Column b, line 10: Line 8 plus line 9
Column b, line 11: KAS-1, schedule 2, page 1, column d, line 5
Column b, line 12: Line 11 plus line 10

Column c, lines 1 - 12: Statement M, page 5 of 5

Column d: Column b less column c

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Operating Income Statement With Pro Forma Adjustments Revenue Adjustment
Adjusted Test Year Ended June 30, 2002

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)	$ 30,893,615	$ (20,407)	$ 30,873,208	$ 249,236	$ 31,122,444
3	Transpiration (489) (including unbilled)	453,665	-	453,665		453,665
4	Other Revenues (488, 493, 495)	147,425	-	147,425		147,425
5	**TOTAL OPERATING REVENUES**	**31,494,705**	**(20,407)**	**31,474,298**	**249,236**	**31,723,534**
6	OPERATING EXPENSES:					
7	Operation and Maintenance:					
8	Natural Gas (accts 728, 804, 805, 808)	21,351,949	-	21,351,949		21,351,949
9	Labor	3,594,005	49,736	3,643,741		3,643,741
10	Benefits Expense	437,498	84,401	521,899		521,899
11	Insurance Expense	118,405	33,911	152,316		152,316
12	Uncollectible Account Expense	81,448	-	81,448		81,448
13	Regulatory Commission Expense	59	11,565	11,624		11,624
14	Other Operation and Maintenance	2,031,324	(11,355)	2,019,969		2,019,969
15	Total Operation and Maintenance	27,614,688	168,258	27,782,946	-	27,782,946
16	Depreciation and Amortization	1,607,620	(128,047)	1,479,573		1,479,573
17	Gain on Sale	-	(45,055)	(45,055)		(45,055)
18	Taxes:					
19	Property Taxes	387,047	14,775	401,822		401,822
20	Payroll Taxes					
21	FICA	250,469	4,486	254,955		254,955
22	Federal Unemployment	3,933	65	3,998		3,998
23	State Unemployment	5,894	80	5,974		5,974
24	Gross Receipts Tax	62,122	(14,912)	47,210	373	47,583
25	Federal Income Taxes	546,059	(205,034)	341,025	87,102	428,127
26	Deferred Income Taxes	(107,226)	-	(107,226)		(107,226)
27	Investment Tax Credit	-	-	-		-
28	Other Taxes	10,531	-	10,531		10,531
29	Total Taxes	1,158,829	(200,540)	958,289	87,475	1,045,764
30	**TOTAL OPERATING EXPENSES**	**30,381,137**	**(205,384)**	**30,175,753**	**87,475**	**30,263,228**
31	**OPERATING INCOME**	**$ 1,113,568**	**$ 184,977**	**$ 1,298,545**	**$ 161,761**	**$ 1,460,306**
32	Rate Base	14,472,899.00		$ 15,799,043		$ 15,799,043
33	Rate of Return	7.694%		8.219%		9.243%
34	Staff Proposed Rate of Return			9.243%		9.243%

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 d, line 4
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 31: KAS-2, Schedule 1, column d, line 32
Column e, line 2: KAS-1, schedule 1, page 1, column b, line 10
Column e, line 23: KAS-1, schedule 1, page 1, column b, line 9
Column e, line 24: 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 31: KAS-2, Schedule 1, column d, line 32

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Operating Income Statement With Pro Forma Adjustments
Adjusted Test Year Ended June 30, 2002

Line No.	Description	South Dakota Per Books	Postage Expense	Interest Synch.	Inflation Adjustment	Plant Adjustments	Ad Valorem Tax Adjustment	Weather Normalization	Labor & Payroll Tax	Benefits
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	OPERATING REVENUES:									
2	Sales (480-485) (including unbilled)	$ 30,893,615						$ (20,407)		
3	Transportation (489) (including unbilled)	453,665								
4	Other Revenues (488, 493, 495)	147,425								
5	**TOTAL OPERATING REVENUES**	**31,494,705**	-	-	-		-	**(20,407)**	-	-
6	OPERATING EXPENSES:									
7	Operation and Maintenance:									
8	Natural Gas (accts 804, 805, 808)	21,351,949								
9	Labor	3,594,005							49,736	
10	Benefits Expense	437,498								84,401
11	Insurance Expense	118,405								
12	Uncollectible Account Expense	81,448								
13	Regulatory Commission Expense	59								
14	Other Operation and Maintenance	2,031,324	7,761		55,463					
15	Total Operation and Maintenance	27,614,688	7,761	-	55,463	-	-	-	49,736	84,401
16	Depreciation and Amortization	1,607,620				52,131				
17	Gain on Sale	-								
18	Taxes:									
19	Property Taxes	387,047					14,775			
20	Payroll Taxes									
21	FICA	250,469	-	-	-	-	-	-	4,486	-
22	Federal Unemployment	3,933	-	-	-	-	-	-	65	-
23	State Unemployment	5,894	-	-	-	-	-	-	80	-
24	Gross Receipts Tax	62,122	-	-	-	-	-	(31)	-	-
25	Federal Income Taxes (35%)	546,059	(2,716)	20,579	(19,412)	(18,246)	(5,171)	(7,132)	(19,028)	(29,540)
26	Deferred Income Taxes	(107,226)								
27	Investment Tax Credit	-								
28	Other Taxes	10,531								
29	Total Taxes	1,158,829	(2,716)	20,579	(19,412)	(18,246)	9,604	(7,163)	(14,397)	(29,540)
30	**TOTAL OPERATING EXPENSES**	**30,381,137**	**5,045**	**20,579**	**36,051**	**33,885**	**9,604**	**(7,163)**	**35,339**	**54,861**
31	**OPERATING INCOME**	**$ 1,113,568**	**$ (5,045)**	**$ (20,579)**	**$ (36,051)**	**$ (33,885)**	**$ (9,604)**	**$ (13,244)**	**$ (35,339)**	**$ (54,861)**
	Source		KAS-1, Sch 4	KAS-1, Sch 5	KAS-1, Sch 6	KAS-2, Sch 5	KAS-2, Sch 5	MCB-1, Sch 1	DAJ-2, Sch 2	DAJ-2, Sch 4
	State Witness Testimony	Senger	Senger	Senger	Senger	Senger	Senger	Senger	Jacobson	Jacobson

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Operating Income Statement With Pro Forma Adjustments
Adjusted Test Year Ended June 30, 2002

Line No.	Description	Insurance	Bonus/ SISP	Federal Income Tax Adjustment	Industry Association Dues	Institutional/ Promotional/ Goodwill Advertising	Economic Development	Rate Case Expense	Depreciation Adjustment	Gross Rcpt Tax
	(a)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
1	OPERATING REVENUES:									
2	Sales (480-485) (including unbilled)									
3	Transportation (489) (including unbilled)									
4	Other Revenues (488, 493, 495)									
5	**TOTAL OPERATING REVENUES**	-	-	-	-	-	-	-	-	-
6	OPERATING EXPENSES:									
7	Operation and Maintenance:									
8	Natural Gas (accts 804, 805, 808)									
9	Labor									
10	Benefits Expense		0							
11	Insurance Expense	33,911								
12	Uncollectible Account Expense									
13	Regulatory Commission Expense							11,565		
14	Other Operation and Maintenance				(33,453)	(39,197)	(1,929)			
15	Total Operation and Maintenance	33,911	-	-	(33,453)	(39,197)	(1,929)	11,565	-	-
16	Depreciation and Amortization								(180,178)	
17	Gain on Sale									
18	Taxes:									
19	Property Taxes									
20	Payroll Taxes									
21	FICA	-	-	-	-	-	-	-	-	-
22	Federal Unemployment	-	-	-	-	-	-	-	-	-
23	State Unemployment	-	-	-	-	-	-	-	-	-
24	Gross Receipts Tax	-	-	-	-	-	-	-	-	(14,881)
25	Federal Income Taxes (35%)	(11,869)	-	(218,593)	11,709	13,719	675	(4,048)	63,062	5,208
26	Deferred Income Taxes									
27	Investment Tax Credit									
28	Other Taxes									
29	Total Taxes	(11,869)	-	(218,593)	11,709	13,719	675	(4,048)	63,062	(9,673)
30	**TOTAL OPERATING EXPENSES**	**22,042**	-	**(218,593)**	**(21,744)**	**(25,478)**	**(1,254)**	**7,517**	**(117,116)**	**(9,673)**
31	**OPERATING INCOME**	**$ (22,042)**	**$ -**	**$ 218,593**	**$ 21,744**	**$ 25,478**	**$ 1,254**	**$ (7,517)**	**$ 117,116**	**$ 9,673**
	Source	DAJ-2, Sch 1	NO ADJ	RGT-2	MMF-1, Sch 1	MMF-1, Sch 2	MMF-1, Sch 3	MMF-1, Sch 4	RGT-1	KAS-1, Sch 7
	State Witness Testimony	Jacobson	Jacobson	Towers	Farris	Farris	Farris	Farris	Towers	Senger

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Operating Income Statement With Pro Forma Adjustments
Adjusted Test Year Ended June 30, 2002

Line No.	Description	Gain on Sale of Off. Building				Total Staff Adjustments	Adjusted Test Year
	(a)	(t)	(u)	(v)	(w)	(x)	(y)
1	OPERATING REVENUES:						
2	Sales (480-485) (including unbilled)					$ (20,407)	$ 30,873,208
3	Transportation (489) (including unbilled)					-	453,665
4	Other Revenues (488, 493, 495)					-	147,425
5	**TOTAL OPERATING REVENUES**	-	-	-	-	**(20,407)**	**31,474,298**
6	OPERATING EXPENSES:						
7	Operation and Maintenance:						
8	Natural Gas (accts 804, 805, 808)					-	21,351,949
9	Labor					49,736	3,643,741
10	Benefits Expense					84,401	521,899
11	Insurance Expense					33,911	152,316
12	Uncollectible Account Expense					-	81,448
13	Regulatory Commission Expense					11,565	11,624
14	Other Operation and Maintenance					(11,355)	2,019,969
15	Total Operation and Maintenance	-	-	-	-	168,258	27,782,946
16	Depreciation and Amortization					(128,047)	1,479,573
17	Gain on Sale	(45,055)				(45,055)	(45,055)
18	Taxes:						
19	Property Taxes					14,775	401,822
20	Payroll Taxes						
21	FICA	-	-	-	-	4,486	254,955
22	Federal Unemployment	-	-	-	-	65	3,998
23	State Unemployment	-	-	-	-	80	5,974
24	Gross Receipts Tax	-	-	-	-	(14,912)	47,210
25	Federal Income Taxes (35%)	15,769	-	-	-	(205,034)	341,025
26	Deferred Income Taxes					-	(107,226)
27	Investment Tax Credit					-	-
28	Other Taxes					-	10,531
29	Total Taxes	15,769	-	-	-	(200,540)	958,289
30	**TOTAL OPERATING EXPENSES**	**(29,286)**	-	-	-	**(205,384)**	**30,175,753**
31	**OPERATING INCOME**	**$ 29,286**	**$ -**	**$ -**	**$ -**	**$ 184,977**	**$ 1,298,545**
	Source	KAS-1, Sch 8					
	State Witness Testimony	Senger					

Montana Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Operating Income Statement With Pro Forma Adjustments
Adjusted Test Year Ended June 30, 2002

SOURCES:

Line 5:	Sum of lines 2 through 4
Line 15:	Sum of lines 8 - 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. d):	(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 5 of 6, Residential Sales - $16,986,636, Firm Gen Sales - $12,000,208, Air Force Sales - $1,346,471, Small Interruptible Sales - $170,207, Large Interruptible Sales - $215,412, and Statement I, page 1 of 6, Unbilled Rev (sales) - $174,682
Column b, line 3:	Sum of: Statement I, page 5 of 6, Small Interruptible Transport - $255,763, Large Interruptible Transport - $204,986, and Statement I, page 1 of 6, Unbilled Rev (Transport) ($7,084)
Column b, line 4:	Statement I, page 2 of 6
Column b, line 8:	Statement H, page 2 of 3 and Schedule H-1, page 12 of 12
Column b, line 9:	Statement H, Schedule H-1, page 4 of 12
Column b, line 10:	Statement H, Schedule H-1, page 5 of 12
Column b, line 11:	Statement H, Schedule H-1, page 6 of 12
Column b, line 12:	Statement H, page 2 of 3, account 904
Column b, line 13:	Statement H, Schedule H-1, page 10 of 12
Column b, line 14:	Sum of: Statement H, Schedule H-1, Page 7 of 12, Postage - $126,807, Page 8 of 12, Industry dues - $42,391, Page 9 of 12, Advertising - $54,970, Page 11 of 12, Other O&M - $1,888,604
Column b, line 16:	Statement J, page 1 of 3
Column b, line 19:	Statement L, page 1 of 1
Column b, line 21:	Statement L, page 1 of 1
Column b, line 22:	Statement L, page 1 of 1
Column b, line 23:	Statement L, page 1 of 1
Column b, line 24:	Statement L, page 1 of 1
Column b, line 25:	Statement K, page 4 of 12
Column b, line 26:	Statement K, page 9 of 12
Column b, line 27:	
Column b, line 28:	Statement L, page 1 of 1, Sum of: Delaware Franchise - $10,353, Highway Use Tax - $72, Secretary of State - $106
Column c, line 14:	KAS-1, Schedule 4, page 1 of 1, column e, line 21
Column d, line 25:	KAS-1, Schedule 5, column b, line 8
Column e, line 14:	KAS-1, Schedule 6, column d, line 9
Column f, line 16:	KAS-2, Schedule 5, column c, line 8
Column g, line 19:	KAS-2, Schedule 5, column b, line 9
Column h, line 2:	MCB-1, Schedule 1, page 1, column b, line 15
Column i, line 9:	DAJ-2, Schedule 2, column b, line 11
Column j, line 10:	DAJ-2, Schedule 4, column d, line 4
Column k, line 11:	DAJ-2, Schedule 1, line 3.
Column l:	Bonus/SISP - Testimony of D. A. Jacobson
Column m, line 25:	RGT-2
Column n, line 14:	MMF-1, Schedule 1, page 1, column c, line 32
Column o, line 14:	MMF-1, Schedule 2, page 1, column d, line 5
Column p, line 14:	MMF-1, Schedule 3, page 1, column c, line 3
Column q, line 13:	MMF-1, Schedule 4, page 1, column c, line 12
Column r, line 16:	RGT-1
Column s, line 24:	KAS-1, Schedule 7, page 1, column c, line 19
Column t, line 14:	KAS-1, Schedule 8, page 1, column b, line 4
Column u	
Column v	
Column w	
Column x:	Sum of columns c through w
Column y:	Column b plus column x

Montana-Dakota Utilities Co.
Docket NG02-011
Postage Expense Adjustment
Adjusted Test Year Ended June 30, 2002

Line	Description	COMPANY ADJUSTMENT		STAFF ADJUSTMENT	
			2002 Budget		Staff Amount
	(a)	(b)	(c)	(d)	(e)
1	Computer Mail		894,386.00		884,190.00
2	Computer mail cost for 2000	115,923.00		115,923.00	
3	Est. Disconnect Notices for 2002	5,152.00		-	
4	Subtotal	121,075.00		115,923.00	
5	Avg. Postage Increase (8.2% - 7.9%)	9,928.15		9,157.92	
6	Total Corporate Mail		131,003.15		125,080.92
7	Business Reply		25,560.00		25,560.00
8	Postage Due		20,416.00		20,416.00
9	Total		1,071,365.15		1,055,246.92
		06/30/2002 Actual Total Company	06/30/2002 Actual - Total Company - GAS	06/30/2002 Actual Total Company	06/30/2002 Actual - Total Company - GAS
10	Regional Mail	165,357.00	105,427.00	165,357.00	105,427.00
11	Office Services	997,835.00	589,712.00	997,835.00	589,712.00
12	Total	1,163,192.00	695,139.00	1,163,192.00	695,139.00
		06/30/02 Total Company with Increase	06/30/02 Total Company - Gas with Increase	06/30/02 Total Company with Increase	06/30/02 Total Company - Gas with Increase
13	Regional Mail (actual *1.082)	178,916.27	114,072.01	178,916.27	114,072.01
14	Office Services (line 9 above)	1,071,365.15	633,167.69	1,055,246.92	623,641.95
15	Total	1,250,281.42	747,239.71	1,234,163.19	737,713.97
16	Percent Increase		7.50%		6.12%
		June 30, 2002 South Dakota Gas	MDU Calculated Effective Postage Rate Increase 7.50%		MDU Calculated Effective Postage Rate Increase 6.12%
17	Distribution	5,283.00	396.23		323.32
18	Customer Accts.	107,587.00	8,069.03		6,584.32
19	Sales	634.00	47.55		38.80
20	A&G	13,303.00	997.73		814.14
21	TOTAL POSTAGE	126,807.00	9,510.53	Staff's Test Year K and M Adj.	7,760.59
22	MDU Projected Amount		136,317.53		

SOURCES:

Column b, lines 2 - 5:	Company response to DR1-2, Support for Statement H, page 43
Column b, lines 10 - 15:	Company response to DR1-2, Support for Statement H, page 42
Column b, lines 17 - 21:	Statement H, Schedule H-1, page 7 of 12
Column c, lines 1, 6 - 9:	Company response to DR1-2, Support for Statement H, page 43
Column c, lines 10 - 16:	Company response to DR1-2, Support for Statement H, page 42
Column c, lines 17 - 21:	Column b * column c, line 16 (7.5%)
Column c, line 22:	Sum of column b line 21 and column c line 21
Column d, line 2:	Column b, line 2 - accepted Company amount
Column d, line 4:	Sum of column d, lines 2 - 3
Column d, line 5:	Column d, line 4 * 7.9%
Column d, lines 10 - 11:	Company response to DR1-2, Support for Statement H, page 42
Column d, line 12:	Sum of column d, lines 10 - 11
Column d, line 13:	Column d, line 10 * 1.079
Column d, line 14:	Column e, line 9
Column d, line 15:	Sum of column d, lines 13 - 14
Column e, line 1:	Column c, line 1 less 1.14% (projected customer increase)
Column e, line 6:	Sum of column c, lines 4 - 5
Column e, line 7:	Column c, line 7 - accepted Company amount
Column e, line 8:	Column c, line 8 - accepted Company amount
Column e, line 9:	Sum of column e, lines 1 - 8
Column e, lines 10 - 11:	Company response to DR1-2, Support for Statement H, page 42
Column e, line 12:	Sum of column e, lines 10 - 11
Column e, line 13:	Column e, line 10 / column d, line 10 * column d, line 13
Column e, line 14:	Column e, line 11 / column d, line 11 * column d, line 14
Column e, line 15:	Sum of column e, lines 13 - 14
Column e, line 16:	Difference between column e, line 15 and line 12 / line 12
Column e, line 17:	Column b, line 17 * column e, line 16
Column e, line 18:	Column b, line 18 * column e, line 16
Column e, line 19:	Column b, line 19 * column e, line 16
Column e, line 20:	Column b, line 20 * column e, line 16
Column e, line 21:	Sum of column e, lines 17 - 20

First-Class Mail

The following information details the R2001–1 changes for First-Class Mail service. This information is intended as an overview only and should not be viewed as defining every DMM revision adopted.

First–Class Mail Rate Highlights

Overall, First–Class Mailr rates will increase an average of 7.9 percent. The single–piece 1–ounce First–Class Mail rate will increase from $0.34 to $0.37, and the single–piece card rate from $0.21 to $0.23. The additional ounce rate for single–piece First–Class Mail items will remain at $0.23. There will be a lower additional ounce rate for Presorted and automation First–Class Mail items.

Business mailers will see larger automation presort discounts. The carrier route automation discount and the nonautomation presort discount will remain at current levels. The proposed increase in automation discounts and the proposed half–cent reduction in the workshare additional–ounce rate will result in more attractive rate incentives, especially for large–volume First–Class Mail service users who presort and mail heavier pieces.

The presort mailing fee will increase from $125 to $150.

First–Class Mail Rate Structure and Mail Preparation

Lower Additional Ounce for Presorted and Automation Rates

Currently, there is a single additional ounce rate for all pieces mailed at First–Class Mail rates. For Presorted and automation pieces weighing more than 2 ounces, a heavy piece discount is deducted.

The Postal Service will implement a lower additional ounce rate for workshare First–Class Mail items. Pieces mailed at single–piece rates will pay $0.23 for each additional ounce; pieces mailed at any workshare rate will pay $0.225 for each additional ounce. This change affects only postage rates.

Automation Basic Rate Split Into Two New Rates

For automation cards and letters, the current rate structure contains a 5–digit, 3–digit, and basic rate. The new rate structure will split the basic rate into an automated area distribution center (AADC) rate (for all pieces in an AADC tray) and a mixed AADC rate (for all pieces in a mixed AADC tray). The AADC rate also will apply to pieces in a less–than–full 3–digit tray. There are no sortation changes for automation cards and letters. The 5–digit sort level will still be optional; all other sort levels will be required.

For automation flats, the current rate structure contains a 5–digit, 3–digit, and basic rate. The new rate structure will split the basic rate into an area distribution center (ADC) rate (for all pieces in an ADC package or tray) and a mixed ADC rate (for all pieces in a mixed ADC package or tray). The ADC rate also will apply to pieces in a less–than–full 3–digit tray. There are no sortation changes for automation flats. The 5–digit sort level still will be optional; all other sort levels will be required.

Nonmachinable Surcharge

The definition of the current nonstandard surcharge will be expanded to include certain physical criteria that could make a mailpiece nonmachinable. Pieces that are nonmachinable are excluded from automated processing and must be handled manually. Nonmachinable pieces also may impede mail flow or damage the mail or mail processing equipment. Manual pieces are considerably more costly to process than machinable letters.

The criteria for nonmachinable letter–size pieces will be listed in DMM C050.2.2. The nonmachinable surcharge will apply to single–piece and Presorted rate letters that weigh 1 ounce or less and meet one or more of the

criteria in that section. Machinable pieces are not subject to any restrictions regarding the OCR read area or barcode clear zone.

The nonmachinable surcharge also will apply to single–piece, Presorted, and automation rate nonletters (flats and parcels) that weigh 1 ounce or less if any one of the following applies:

(a) The piece is greater than 1/4–inch thick.

(b) The length is more than 11–1/2 inches or the height is more than 6–1/8 inches.

(c) The aspect ratio (length divided by height) is less than 1.3 or more than 2.5.

The nonmachinable surcharge will be $0.12 for single–piece rate pieces and $0.055 for Presorted and automation rate pieces.

The nonmachinable criteria in C050.2.2 do not apply to pieces mailed at any card rate.

The nonmachinable surcharge will apply to letter–size pieces (but not card–rate pieces) for which the mailer has chosen the manual only (do not automate) option. For card–rate pieces, a mailer can specify manual handling, but they will not be charged a surcharge.

This change is consistent with the addition of a nonmachinable surcharge for Standard Mail service.

In conjunction with this change, trays of machinable and nonmachinable letters will be prepared and labeled differently. The preparation for machinable letters will be similar to the current preparation for upgradable letters (e.g., no packaging, optional 5–digit sort level); the preparation for nonmachinable pieces will be similar to the current package–based preparation for Presorted letters. The current weight limit for upgradable letters (2.5 ounces) will be replaced with a weight limit of 3.3 ounces for machinable letters. Letters heavier than 3.3 ounces and less than 1/4–inch thick will use the nonmachinable preparation and labeling but will not pay the surcharge (because it applies only to pieces that weigh 1 ounce or less).

On tray labels, the current "NON BC" (not barcoded) designation will be replaced with one of two designations: "MACH" for machinable pieces or "MANUAL" for nonmachinable pieces. Although card– rate pieces will not be subject to the surcharge, mailers will be required to show on the tray label whether or not those pieces are machinable (for instance, a double card that is not tabbed is not machinable). The "MANUAL" designation will help the Postal Service direct trays of mail to the appropriate mail processing operation. As is currently required, mailers who choose the "do not automate" option will show "MANUAL" on Line 2 of the tray label.

Barcoded tray labels are allowed, but are not required, for trays of First–Class Mail machinable letters. Zebra codes must not be used on trays of First–Class Mail machinable letters. (Zebra codes indicate that the tray contains automation rate prebarcoded mail.)

There are no preparation or labeling changes for Presorted flats or parcels subject to the surcharge.

Mail preparation instructions for Presorted letter–size pieces subject to the nonmachinable surcharge will be included in DMM M130. Preparation instructions for automation flats subject to the nonmachinable surcharge will not change (see current DMM M820).

The nonmachinable surcharge will be assessed on any piece mailed out as a different class of mail and returned as a First–Class Mail item (for instance, a Standard Mail item endorsed "Return Service Requested") if the piece weighs 1 ounce or less and meets the criteria for nonmachinability in C050.2.2. Pieces returned at First–Class Mail card rates will not be subject to the nonmachinable surcharge.

The nonmachinable surcharge will take effect when new rates are implemented; however, mailers have until January 1, 2003, to comply with the mail preparation and tray labeling changes.

Delivery Confirmation and Signature Confirmation for First–Class Mail Parcels

The Postal Service will add two new special service options for First–Class Mail parcels: Delivery Confirmation ™ service and Signature Confirmation ™ service. Both services will be available in manual (retail) and electronic options. The fees for Delivery Confirmation service will be $0.55 (retail) and $0.13 (electronic). The fees for Signature Confirmation service will be $1.80 (retail) and $1.30 (electronic).

For the purposes of adding Delivery Confirmation service or Signature Confirmation service, a First–Class Mail parcel is defined as any piece that:

(a) Has an address side with enough surface area to fit the delivery address, return address, postage, markings and endorsements, and special service label; and

(b) Is in a box or, if not in a box, is greater than 3/4–inch thick at its thickest point.

This definition will provide mailers many different packaging options for their First–Class Mail parcels.

Containerization and Labeling

For letter–size pieces, a full tray will be defined as one that is 100 percent full, with a range between 75 percent and 100 percent. The recommended default for presort software will be 85 percent. In addition, after the minimum volume for rate eligibility is reached (i.e., 150 pieces for a 3–digit area), overflow will be optional for all sort levels of letter trays. Also, mailers will be required to use as few trays as possible: Under current standards, a mailer could prepare one full 1–foot tray plus one less–than–full 1–foot tray; new standards will result in the preparation of a single less–than–full 2–foot tray.

On all First–Class Mail letter trays, "LTRS" will change to "LTR" and "CR–RTS" will change to "CR–RT." This change is necessary to allow more room for other information on the tray label. Mailers have until January 1, 2003, to comply with these labeling changes.

Documentation

Mailers will no longer be required to present a hard copy PS Form 3553, *Coding Accuracy Support System (CASS) Summary Report*, with their mailings. Instead, mailers or mailer agents will continue to keep this documentation on file for 1 year from the date of mailing and make it available to the Postal Service on 24–hour notice.

Software vendors and mailers should note that changes will be made to manifest keyline rate codes (DMM P910.3.0) and multiline optical character reader (MLOCR) rate markings (DMM P960.3.0) to reflect the new First–Class Mail rate categories.

Montana-Dakota Utilities Co.
Docket NG02-011
Interest Synchonization Adjustment
Adjusted Test Year Ended June 30, 2002

Line	**Description**	**Amount**	
	(a)	(b)	
1	Average Rate Base	$ 15,799,043	
2	CWIP (not included in rate base)	-	1986 tax law change
3	Investment To Be Financed	15,799,043	
4	Weighted Cost of Debt	4.001%	
5	Synchronized Interest Expense	632,175	
6	Interest Expense as filed	690,972	
7	Difference In Interest Expense	(58,797)	
8	Federal Income Tax Adjustment (35%)	**$ 20,579**	

SOURCES:
Column b, line 1: KAS-2, schedule 1, page 1, column d, line 32
Column b, line 2: Zero - 1986 tax law change
Column b, line 3: Line 1 plus line 2
Column b, line 4: BLC-1, schedule 1,column c, line 1
Column b, line 5: Line 3 times line 4
Column b, line 6: Statement K, page 4 of 12
Column b, line 7: Line 5 less line 6
Column b, line 8: line 7 times 35% (inverse)

Montana-Dakota Utilities Co.
Docket NG02-011
Inflation Adjustment
Adjusted Test Year Ended June 30, 2002

Line	Function	06/30/02 Other O & M	Annualized 06/30/02 Other O & M Amount 0.534%	Adjusted for Inflation at 2.390%
	(a)	(b)	(c)	(d)
1	**Other Gas Supply**	8,086	8,129	8,323
2	**Distribution**	835,943	840,407	860,493
3	**Customer Accounts**	319,469	321,175	328,851
4	**Customer Services & Information**	10,172	10,226	10,470
5	**Sales**	40,636	40,853	41,829
6	**Administrative and General**	674,298	677,899	694,101
7	**TOTAL**	1,888,604	1,898,689	1,944,067
8	**Less Per Books**			1,888,604
9	**Staff Adjustment to Per Books**			**55,463**

		June 01	June 02	Change
10	**Test Year CPI**	178	179.9	1.067%
11	**1/2 Test Year CPI**			0.534%

		June 02	Mar 03	Change
12	**Post Test Year CPI**	179.9	184.2	2.390%

SOURCES:

Column b, lines 1 - 7:	Statement H, Schedule H-1, page 11 of 2
Column b, lines 10 & 12:	KAS-1, Schedule 6, page 2 of 2
Column c, lines 1 - 6:	Column b * column d, line 11
Column c, line 7:	Sum of column c, lines 1 - 6
Column c, lines 10 & 12:	KAS-1, Schedule 6, page 2 of 2
Column d, lines 1 - 6:	Column c * column d, line 12
Column d, line 7:	Sum of column d, lines 1 - 6
Column d, line 8:	Column b, line 7
Column d, line 9:	Column d, line 7 less column d, line 8
Column d, line 10:	Difference between column c, line 10 and column b, line 10 / column b line 10
Column d, line 11:	Column d, line 10 / 2
Column d, line 12:	Difference between column c, line 12 and column b, line 12 / column b line 12

Montana-Dakota Utilities Co.
Docket NG02-011
Inflation Adjustment
Adjusted Test Year Ended June 30, 2002

Series Id: CUUR0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	HALF1	HALF2
1993	142.6	143.1	143.6	144	144.2	144.4	144.4	144.8	145.1	145.7	145.8	145.8	144.5	143.7	145.3
1994	146.2	146.7	147.2	147.4	147.5	148	148.4	149	149.4	149.5	149.7	149.7	148.2	147.2	149.3
1995	150.3	150.9	151.4	151.9	152.2	152.5	152.5	152.9	153.2	153.7	153.6	153.5	152.4	151.5	153.2
1996	154.4	154.9	155.7	156.3	156.6	156.7	157	157.3	157.8	158.3	158.6	158.6	156.9	155.8	157.9
1997	159.1	159.6	160	160.2	160.1	160.3	160.5	160.8	161.2	161.6	161.5	161.3	160.5	159.9	161.2
1998	161.6	161.9	162.2	162.5	162.8	163	163.2	163.4	163.6	164	164	163.9	163	162.3	163.7
1999	164.3	164.5	165	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3	166.6	165.4	167.8
2000	168.8	169.8	171.2	171.3	171.5	172.4	172.8	172.8	173.7	174	174.1	174	172.2	170.8	173.6
2001	175.1	175.8	176.2	176.9	177.7	178	177.5	177.5	178.3	177.7	177.4	176.7	177.1	176.6	177.5
2002	177.1	177.8	178.8	179.8	179.8	179.9	180.1	180.7	181	181.3	181.3	180.9	179.9	178.9	180.9
2003	181.7	183.1	184.2												

Source:
Downloaded from
U.S. Department of Labor, Bureau of Labor Statistics Website
http://data.bls.gov/cgi-bin/surveymost?cu
U.S. All items, 1982-84=100 - CUUR0000SA0
as of 4/21/2003

Montana-Dakota Utilities Co.
Docket NG02-011
Gross Receipts Tax
Adjusted Test Year Ended June 30, 2002

Line	Description	South Dakota Per Books Test Year	Gross Receipts TAX 0.15%
	(a)	(b)	(c)
1	Sales		
2	Residential	$ 16,986,636	$ 25,480
3	Firm General	12,000,208	18,000
4	Air Force	1,346,470	2,020
5	Small Interruptible	170,207	255
6	Large Interruptible	215,412	323
7	Unbilled	174,682	262
8	TOTAL SALES	30,893,615	46,340
9	Transportation		
10	Small Interruptible	255,763	384
11	Large Interruptible	204,986	307
12	Unbilled	(7,084)	(11)
13	TOTAL TRANSPORTATION	453,665	680
14	Miscellaneous Service Rev	39,820	60
15	Rent from Gas Property	84,274	126
16	Other Revenue	23,331	35
17	TOTAL	31,494,705	47,241
18	Test Year GRT		62,122
19	Difference (Staff Adjustment)		**$ (14,881)**

SOURCES:

Column b, lines 1 through 13: Statement I, page 1 of 6
Column b, lines 14 through 16: Statement I, page 2 of 6

Column c, line 18: Statement L, page 1 of 1

Montana-Dakota Utilities Co.
Docket NG02-011
Gain on the Sale of Office Building
Adjusted Test Year Ending June 30, 2002

Line	**Description**	**Amount**	Source:
	(a)	(b)	
1	Gain on the Sale of Rapid City office building	$ 260,280	MDU response to DR3-53
2	Building Allocation to Black Hills Gas	86.55064%	
3	Black Hills Gas portion of Gain	225,274	Per Tamie Aberle - 4/21/03
4	Five Year Amortization	**$ 45,055**	

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Average Rate Base with Pro Forma Adjustments
Adjusted Test Year Ending June 30, 2002

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)	$ 29,566,276		$ -	$ 29,566,276
3	General (including Intangible - 303)	6,275,400		1,964,504	8,239,904
4	Common (including Intangible 303)	2,077,553		-	2,077,553
5	Total Gas Plant in Service (101)	37,919,229		1,964,504	39,883,733
6	Gas - Completed Construction Not Classified (106)	1,256,966		-	1,256,966
7	Total Plant in Service (101 and 106)	39,176,195		1,964,504	41,140,699
8	Accumulated Depreciation				
9	Distribution (including Intangible)	19,632,677	1/	90,089	19,722,766
10	General (including Intangible)	2,389,024	1/	39,311	2,428,335
11	Common (including Intangible)	856,323	1/	-	856,323
12	Total Accumulated Depreciation	22,878,024		129,400	23,007,424
13	TOTAL NET GAS PLANT IN SERVICE	16,298,171		1,835,104	18,133,275
14	Additions to Rate Base:				
15	Material and Supplies	247,865		6,209	254,074
16	Fuel Stocks	-		-	-
17	Prepayments	51,443		(3,496)	47,947
18	Advanced Tax Collection	-		(75,482)	(75,482)
19	Working Capital	-		(334,208)	(334,208)
20	Other	174,494		(9,253)	165,241
21	TOTAL ADDITIONS TO RATE BASE	473,802		(416,230)	57,572
22	Deductions to Rate Base:				
23	Accumulated Deferred Income Taxes	1,842,858		-	1,842,858
24	Accumulated Investment Tax Credit	39,527		88,219	127,746
25	Customer Advances for Construction	85,591		4,511	90,102
26	Customer Deposits	131,122		-	131,122
27	Accumulated Provision for Uncollectibles	52,168		-	52,168
28	Accumulated Provision for Injuries and Damages	147,808		-	147,808
29	Miscellaneous Operating Provisions	-		-	-
30	Other	-		-	-
31	TOTAL DEDUCTIONS TO RATE BASE	2,299,074		92,730	2,391,804
32	**TOTAL SOUTH DAKOTA RATE BASE**	**$ 14,472,899**		**$ 1,326,144**	**$ 15,799,043**

footnote:
1/ Accumulated depreciation amounts are **NOT** a 13 month average. They are 6-30-01 / 6-30-02 average balance. Company did not provide a 13 month average balance. See the testimony of Staff Witness Senger.

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 NG02-011
South Dakota Average Rate Base with Pro Forma Adjustments
Adjusted Test Year Ending June 30, 2002

Line No.	Description	South Dakota Test Year Average Per Books	Plant Adjustments	Depreciation Adjustment	Updates	Working Capital	Investment Tax Credit		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)	$ 29,566,276							-	$ 29,566,276
3	General (including Intangible - 303)	6,275,400	1,964,504						1,964,504	8,239,904
4	Common (including Intangible 303)	2,077,553							-	2,077,553
5	Total Gas Plant in Service (101)	37,919,229	1,964,504	-	-	-	-	-	1,964,504	39,883,733
6	Gas - Completed Construction Not Classified (106)	1,256,966							-	1,256,966
7	Total Gas Plant in Service (101 and 106)	39,176,195	1,964,504	-	-	-	-	-	1,964,504	41,140,699
8	Accumulated Depreciation									
9	Distribution (including Intangible)	19,632,677 1/		90,089					90,089	19,722,766
10	General (including Intangible)	2,389,024 1/	39,311						39,311	2,428,335
11	Common (including Intangible)	856,323 1/							-	856,323
12	Total Accumulated Depreciation	22,878,024	39,311	90,089	-	-	-	-	129,400	23,007,424
13	TOTAL NET GAS PLANT IN SERVICE	16,298,171	1,925,193	(90,089)	-	-	-	-	1,835,104	18,133,275
14	Additions to Rate Base:									
15	Material and Supplies	247,865			6,209				6,209	254,074
16	Fuel Stocks	-							-	-
17	Prepayments	51,443			(3,496)				(3,496)	47,947
18	Advanced Tax Collection	-				(75,482)			(75,482)	(75,482)
19	Working Capital	-				(334,208)			(334,208)	(334,208)
20	Other	174,494			(9,253)				(9,253)	165,241
21	TOTAL ADDITIONS TO RATE BASE	473,802	-	-	(6,540)	(409,690)	-	-	(416,230)	57,572
22	Deductions to Rate Base:									
23	Accumulated Deferred Income Taxes	1,842,858							-	1,842,858
24	Accumulated Investment Tax Credit	39,527					88,219		88,219	127,746
25	Customer Advances for Construction	85,591			4,511				4,511	90,102
26	Customer Deposits	131,122							-	131,122
27	Accumulated Provision for Uncollectibles	52,168							-	52,168
28	Accumulated Provision for Injuries and Damages	147,808							-	147,808
29	Miscellaneous Operating Provisions	-							-	-
30	Other	-							-	-
31	TOTAL DEDUCTIONS TO RATE BASE	2,299,074	-	-	4,511	-	88,219	-	92,730	2,391,804
32	**TOTAL SOUTH DAKOTA RATE BASE**	**$ 14,472,899**	**1,925,193**	**(90,089)**	**(11,051)**	**(409,690)**	**(88,219)**	**-**	**1,326,144**	**$ 15,799,043**
	Source		KAS-2, Sch 5	RGT-1	DAJ-1, Sch 3	DAJ-1, Sch 1&2	KAS-2, Sch 4			
	Staff Witness Testimony	Senger	Senger	Towers	Jacobson	Jacobson	Senger			

footnote:
1/ Accumulated depreciation amounts are **NOT** a 13 month average. They are 6-30-01 / 6-30-02 average balance.
Company was unable to provide a 13 month average balance. See the testimony of Staff Witness Senger.

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Average Rate Base with Pro Forma Adjustments
Adjusted Test Year Ending June 30, 2002

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:	Statement D, Schedule D-3, Page 1 of 2, Total Distribution Plant - 12 Month Average
Column b, line 3:	Statement D, Schedule D-3, Page 1 of 2, Total General Plant - 12 Month Average (6,137,051) plus Intangible Plant - General - 12 Month Average (138,349)
Column b, line 4:	Statement D, Schedule D-3, Page 2 of 2, Total Common Plant - 12 Month Average (1,083,942) plus Intangible Plant - Common - 12 Month Average (993,611)
Column b, line 6:	KAS-2, Schedule 3, Page 3 of 4 Column c , line 15
Column b, line 9:	Statement E, Page 1 of 4, 6/30/02 average - Distribution
Column b, line 10:	Statement E, Page 1 of 4, 6/30/02 average General (2,256,456) plus 6/30/02 average Intangible General (132,568)
Column b, line 11:	Statement E, Page 1 of 4, 6/30/02 average Common (494,061) plus 6/30/02 Intangible Common (362,262)
Column b, line 15:	KAS-2, Schedule 3, Column c, line 15
Column b, line 16:	Amount = 0, per DR4-25
Column b, line 17:	KAS-2, Schedule 3, Column e, line 15
Column b, line 18:	N/A
Column b, line 19:	N/A
Column b, line 20:	KAS-2, Schedule 3, Column g, line 15
Column b, line 23:	KAS-2, Schedule 3, page 2 of 3, Column e, Line 15
Column b, line 24:	KAS-2, Schedule 3, Page 2 of 3, Column g, Line 15
Column b, line 25:	KAS-2, Schedule 3, Page 1 of 3, Column I, line 15
Column b, line 26:	KAS-2, Schedule 3, Page 2 of 3, Column h, line 16
Column b, line 27:	KAS-2, Schedule 3, Page 3 of 3, Column c, line 15
Column b, line 28:	KAS-2, Schedule 3, Page 3 of 3, Column e, line 16
Column b, line 29:	Amount = 0, per DR4-24
Column b, line 30:	N/A
Column c, line 3:	KAS-2, Schedule 5, column b, line 8
Column c, line 10:	KAS-2, Schedule 5, column d, line 8
Column d, line 9:	RGT-1
Column e, line 15:	DAJ-1, Schedule 3, page 1, column d, line 1
Column e, line 17:	DAJ-1, Schedule 3, page 1, column d, line 2
Column e, line 20:	DAJ-1, Schedule 3, page 1, column d, line 3
Column e, line 25:	DAJ-1, Schedule 3, page 1, column d, line 4
Column f, line 18:	DAJ-1, Schedule 2, page 1, column g, line 4
Column f, line 19:	DAJ-1, Schedule 1, page 1, column b, line 24
Column g, line 24:	KAS-2, Schedule 4, column d, line 8
Column h:	N/A
Column i:	Sum of columns c through I
Column j:	Column b plus column j

Montana-Dakota Utilities Co.
Docket NG02-011
Twelve-month Average Balances
Adjusted Test Year Ending June 30, 2002

		MATERIAL AND SUPPLIES		PREPAID INSURANCE		UNAMORTIZED FAS 106		CUSTOMER ADVANCES FOR CONSTRUCTION	
Line	MONTH	Ending Balance	Average Balance	Ending Balance	Average Balance	Ending Balance	Average Balance	Ending Balance	Average Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Jun-2001	281,081.00	-	45,645.00	-	182,426.00		152,323.00	
2	Jul-2001	266,912.00	273,996.50	39,398.00	42,521.50	181,104.00	181,765.00	69,907.00	111,115.00
3	Aug-2001	291,248.00	279,080.00	39,450.00	39,424.00	179,782.00	180,443.00	70,113.00	70,010.00
4	Sep-2001	265,291.00	278,269.50	33,019.00	36,234.50	178,460.00	179,121.00	70,148.00	70,130.50
5	Oct-2001	274,796.00	270,043.50	25,306.00	29,162.50	177,138.00	177,799.00	70,266.00	70,207.00
6	Nov-2001	227,342.00	251,069.00	19,119.00	22,212.50	175,816.00	176,477.00	71,651.00	70,958.50
7	Dec-2001	215,239.00	221,290.50	11,361.00	15,240.00	174,494.00	175,155.00	71,841.00	71,746.00
8	Jan-2002	203,557.00	209,398.00	92,476.00	51,918.50	173,172.00	173,833.00	95,255.00	83,548.00
9	Feb-2002	202,311.00	202,934.00	89,871.00	91,173.50	171,850.00	172,511.00	95,595.00	95,425.00
10	Mar-2002	249,521.00	225,916.00	80,660.00	85,265.50	170,529.00	171,189.50	95,813.00	95,704.00
11	Apr-2002	243,926.00	246,723.50	70,227.00	75,443.50	169,207.00	169,868.00	95,976.00	95,894.50
12	May-2002	243,876.00	243,901.00	65,613.00	67,920.00	167,885.00	168,546.00	96,188.00	96,082.00
13	Jun-2002	299,635.00	271,755.50	55,991.00	60,802.00	166,563.00	167,224.00	96,351.00	96,269.50
14	TOTAL	3,264,735.00	2,974,377.00	668,136.00	617,318.00	2,268,426.00	2,093,931.50	1,151,427.00	1,027,090.00
15	AVERAGE	251,133.46	**247,864.75**	51,395.08	**51,443.17**	174,494.31	**174,494.29**	88,571.31	**85,590.83**
		Source: Statement F Sch F-1 Page 2 of 5	**To** KAS-2, Sch 2 Col. b, line 15	**Source:** Statement F Sch F-1 Page 3 of 5	**To** KAS-2, Sch 2 Col. b, line 17	**Source:** Statement F Sch F-1 Page 4 of 5	**To** KAS-2, Sch 2 Col. b, line 20	**Source:** Statement F Sch F-1 Page 5 of 5	**To** KAS-2, Sch 2 Col. b, line 24

Montana-Dakota Utilities Co.
Docket NG02-011
Twelve-month Average Balances
Adjusted Test Year Ending June 30, 2002

		COMPLETED CONSTRUCTION NOT CLASSIFIED		ACCUMULATED DEFERRED INCOME TAXES		ACCUMULATED INVESTMENT TAX CREDIT		CUSTOMER DEPOSITS SD - TOTAL COMPANY	
Line	MONTH	Ending Balance	Average Balance	Ending Balance	Average Balance	Ending Balance	Average Balance	Ending Balance	Average Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Jun-2001	820,487.00	-	1,860,422.00	-	46,069.00		154,186.00	
2	Jul-2001	886,430.00	853,458.50	1,857,031.00	1,858,726.50	44,650.00	45,359.50	152,652.00	153,419.00
3	Aug-2001	733,921.00	810,175.50	1,853,640.00	1,855,335.50	43,230.00	43,940.00	152,954.00	152,803.00
4	Sep-2001	882,147.00	808,034.00	1,850,250.00	1,851,945.00	41,810.00	42,520.00	160,619.00	156,786.50
5	Oct-2001	866,979.00	874,563.00	1,846,859.00	1,848,554.50	40,390.00	41,100.00	176,914.00	168,766.50
6	Nov-2001	867,630.00	867,304.50	1,853,624.00	1,850,241.50	38,970.00	39,680.00	189,307.00	183,110.50
7	Dec-2001	906,820.00	887,225.00	1,847,830.00	1,850,727.00	40,710.00	39,840.00	196,307.00	192,807.00
8	Jan-2002	4,280,443.00	2,593,631.50	1,840,493.00	1,844,161.50	39,470.00	40,090.00	207,215.00	201,761.00
9	Feb-2002	4,488,221.00	4,384,332.00	1,836,664.00	1,838,578.50	38,226.00	38,848.00	213,988.00	210,601.50
10	Mar-2002	120,562.00	2,304,391.50	1,832,836.00	1,834,750.00	36,981.00	37,603.50	211,931.00	212,959.50
11	Apr-2002	223,862.00	172,212.00	1,829,007.00	1,830,921.50	35,737.00	36,359.00	208,732.00	210,331.50
12	May-2002	289,009.00	256,435.50	1,825,178.00	1,827,092.50	34,492.00	35,114.50	210,548.00	209,640.00
13	Jun-2002	254,640.00	271,824.50	1,821,350.00	1,823,264.00	33,248.00	33,870.00	204,864.00	207,706.00
14	TOTAL	15,621,151.00	15,083,587.50	23,955,184.00	22,114,298.00	513,983.00	474,324.50	2,440,217.00	2,260,692.00
15	AVERAGE	1,201,627.00	**1,256,965.63**	1,842,706.46	**1,842,858.17**	39,537.15	**39,527.04**	187,709.00	188,391.00
16								SD/BH Gas Rev Allocation (69.6%)	**131,121.54**
		Source: Company Response to DR4-15	**To** KAS-2, Sch 2 Col. b, line 6	**Source:** Company Response to DR4-17	**To** KAS-2, Sch 2 Col. b, line 23	**Source:** Company Response to DR4-18	**To** KAS-2, Sch 2 Col. b, line 23	**Source:** Company Response to DR4-19	**To** KAS-2, Sch 2 Col. b, line 25

Montana-Dakota Utilities Co.
Docket NG02-011
Twelve-month Average Balances
Adjusted Test Year Ending June 30, 2002

Line	MONTH	ACCUMULATED PROVISION FOR UNCOLLECTIBLES		TOTAL UTILITY ACCUMULATED PROVISION FOR INJURIES & DAMAGES					
		Ending Balance	Average Balance	Ending Balance	Average Balance	Ending Balance	Average Balance	Ending Balance	Average Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Jun-2001**	105,705.00	-	1,421,290.00	-				
2	**Jul-2001**	91,291.00	98,498.00	1,373,451.00	1,397,370.50		-		-
3	**Aug-2001**	75,236.00	83,263.50	1,363,848.00	1,368,649.50		-		-
4	**Sep-2001**	62,902.00	69,069.00	1,355,150.00	1,359,499.00		-		-
5	**Oct-2001**	56,668.00	59,785.00	1,348,492.00	1,351,821.00		-		-
6	**Nov-2001**	52,526.00	54,597.00	1,315,301.00	1,331,896.50		-		-
7	**Dec-2001**	30,095.00	41,310.50	1,302,912.00	1,309,106.50		-		-
8	**Jan-2002**	36,415.00	33,255.00	1,265,575.00	1,284,243.50		-		-
9	**Feb-2002**	39,241.00	37,828.00	1,501,697.00	1,383,636.00		-		-
10	**Mar-2002**	39,561.00	39,401.00	1,497,682.00	1,499,689.50		-		-
11	**Apr-2002**	36,653.00	38,107.00	1,493,010.00	1,495,346.00		-		-
12	**May-2002**	38,175.00	37,414.00	1,487,725.00	1,490,367.50		-		-
13	**Jun-2002**	28,806.00	33,490.50	1,482,288.00	1,485,006.50		-		-
14	**TOTAL**	693,274.00	626,018.50	18,208,421.00	16,756,632.00	-	-	-	-
15	**AVERAGE**	53,328.77	**52,168.21**	1,400,647.77	1,396,386.00	-	**-**	-	**-**
			SD/BH Gas Rev Allocation (10.585%)		**147,808.00**				
		Source: Company Response to DR4-20	**To** KAS-2, Sch 2 Col. b, line 26	**Source:** Company Response to DR4-22	**To** KAS-2, Sch 2 Col. b, line 27	**Source:**	**To**	**Source:**	**To**

Montana-Dakota Utilities Co.
Docket NG02-011
Twelve-month Average Balances
Adjusted Test Year Ending June 30, 2002

	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
1/1/01 to 12/31/01 (December 2001 YTD)	138,643,545	10,142,488	237,217,664	46,672,665	4,969,311
Less **1/1/01 to 6/30/01** (June 2001 YTD)	68,065,732	5,013,255	184,620,617	35,744,183	3,908,670
Sub Total **7/1/01 to 12/31/01**	**70,577,813**	**5,129,233**	**52,597,047**	**10,928,482**	**1,060,641**
ADD **1/1/02 to 6/30/02** (June 2002 YTD)	68,413,503	4,925,942	102,975,575	20,251,225	2,502,428
TOTAL (test year) **7/01/01 to 6/30/02**	**138,991,316**	**10,055,175**	**155,572,622**	**31,179,707**	**3,563,069**

SD Black Hills Gas as % of Total SD Utility (SD gas and electric) **69.6007%**

SD Black Hills gas as percent of Total Utility (all gas and electric) **10.5850%**

SOURCE: MDU Monthly reports - excluding "Other Operating Revenue"

Montana-Dakota Utilities Co.
Docket NG02-011
Accumulated Deferred Investment Tax Credit
Adjusted Test Year Ending June 30, 2002

Line	(a)	Gas Plant (b)	Common Plant (c)	TOTAL (d)
1	Unamortized ITC - 26.4 yr. Life Balance at 12/31/2002	647,953	121,172	
2	SD Gross Plant - Juris. No. 37	18.860517%		
3	Common Split - Gas - Utility No. 26		36.794625%	
4	Allocation subtotal		44,585	
5	SD Common Plant - Juris. No. 221		12.424473%	
6	South Dakota Allocation	122,207	5,539	$ 127,746
7	Staff per books ITC			39,527
8	Difference (Staff adjustment to per books)			**88,219**

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 NG02-011
Plant Adjustment
Adjusted Test Year Ending June 30, 2002

Line	Description	Plant Balance	Depreciation Expense	Average Accumulated Depreciation
	(a)	(b)	(c)	(d)
	Annualized			
1	Struct. & Improv. (390)	$ 3,785,282	$ 91,980	$ 49,823
2	Land (389)	578,767	-	-
3	**Subtotal**	4,364,049	91,980	49,823
	LESS			
	Per Books			
4	Struct. & Improv. (390)	1,552,482	37,722	9,448
5	Land (389)	242,963		
	CWIP in Service			
	Struct. & Improv. (390)			
6	Jan & Feb 2002	525,255	2,127	1,064
	CWIP in Service			
	Land (389)			
7	Jan & Feb 2002	78,845		
8	**Staff Adjustment**	**$ 1,964,504**	**$ 52,131**	**$ 39,311**
	Effective Ad Valorem			
9	**Tax Rate - Gen 0.7521%**	**$ 14,775**		

SOURCES:

Column b
Line 1: KAS-2, Sch 5, page 2 of 2, column e, line 14
Line 2: KAS-2, Sch 5, page 3, column e, line 14
Line 4: KAS-2, Sch 5, page 2 of 2, column b, line 14
Line 5: KAS-2, Sch 5, page 3, column b, line 14
Line 6: 2 months of Plant increase for CWIP in Service - KAS-2 Sch 5, p2, col b ,line 15 Acct 390 June Ave less Feb Avg divided by 12 months times 2 months
Line 7: 2 months of Land increase for CWIP in Service - KAS-2 Sch 5, p3, col b ,line 15 Acct 389 June Ave less Feb Avg divided by 12 months times 2 months
Line 9: Column b, line 8 times 0.7521%

Column c
Line 1: KAS-2, Sch 5, page 2 of 2, column f, line 13
Line 4: KAS-2, Sch 5, page 2 of 2, column c, line 13
Line 6: Col a, line 6 times 2.43% div 12 times 2

Column d
Line 1: KAS-2, Sch 5, page 2 of 2, column g, line 14
Line 4: KAS-2, Sch 5, page 2 of 2, column d, line 14
Line 6: Col c, line 6 divided by 2

Montana-Dakota Utilities Co.
Docket NG02-011
Plant Adjustment
Adjusted Test Year Ending June 30, 2002

		Actual Plant in Service Per Books General Plant - Structures and Improvements (390)			Annualized using June Average General Plant - Structures and Improvements (390)		
Line	Description	Account 390 Structures & Improvements Average Balance	Calculated Depreciation Expense Based on a 2.43% Annual Depr. Rate	Test Year Calculated Increase in Accumulated Depreciation	Account 390 Structures & Improvements Average Balance	Calculated Depreciation Expense Based on a 2.43% Annual Depr. Rate	Test Year Calculated Increase in Accumulated Depreciation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**July 01**	633,712	1,283	-	3,785,282	7,665	7,665
2	**Aug 01**	633,712	1,283	1,283	3,785,282	7,665	15,330
3	**Sept 01**	633,712	1,283	2,566	3,785,282	7,665	22,995
4	**Oct 01**	633,712	1,283	3,849	3,785,282	7,665	30,660
5	**Nov 01**	633,712	1,283	5,132	3,785,282	7,665	38,325
6	**Dec 01**	633,712	1,283	6,415	3,785,282	7,665	45,990
7	**Jan 02**	633,732	1,283	7,698	3,785,282	7,665	53,655
8	**Feb 02**	633,752	1,283	8,981	3,785,282	7,665	61,320
9	**Mar 02**	2,207,526	4,470	10,264	3,785,282	7,665	68,985
10	**Apr 02**	3,782,841	7,660	14,734	3,785,282	7,665	76,650
11	**May 02**	3,784,383	7,663	22,394	3,785,282	7,665	84,315
12	**June 02**	3,785,282	7,665	30,057	3,785,282	7,665	91,980
13	**TOTAL**	**3,151,570**	**37,722**			**91,980**	
14	**Average**	**1,552,482**		**9,448**	**3,785,282**		**49,823**
15	**Difference (June less Feb)**	**3,151,530**					

SOURCES:
Column b: Statement D, Schedule D-3, page 1 of 2, General Plant, account 390 - Structures and Improvements

Montana-Dakota Utilities Co.
Docket NG02-011
Plant Adjustment
Adjusted Test Year Ending June 30, 2002

		Actual Plant in Service Per Books General Plant - Land - account 389			Annualized using June Average General Plant - Land - account 389		
Line	Description	Account 389 Land Average Balance	Calculated Depreciation Expense Based on a 0% Annual Depr. Rate	Test Year Calculated Increase in Accumulated Depreciation	Account 390 Structures & Improvements Average Balance	Calculated Depreciation Expense Based on a 2.43% Annual Depr. Rate	Test Year Calculated Increase in Accumulated Depreciation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**July 01**	105,845	-	-	578,767	-	-
2	**Aug 01**	105,845	-	-	578,767	-	-
3	**Sept 01**	105,845	-	-	578,767	-	-
4	**Oct 01**	105,845	-	-	578,767	-	-
5	**Nov 01**	105,845	-	-	578,767	-	-
6	**Dec 01**	105,845	-	-	578,767	-	-
7	**Jan 02**	105,849	-	-	578,767	-	-
8	**Feb 02**	105,695	-	-	578,767	-	-
9	**Mar 02**	339,877	-	-	578,767	-	-
10	**Apr 02**	574,837	-	-	578,767	-	-
11	**May 02**	575,457	-	-	578,767	-	-
12	**June 02**	578,767	-	-	578,767	-	-
13	**TOTAL**		-			-	
14	**Average**	**242,963**		-	**578,767**		-
15	**Difference (June less Feb)**	**473,072**					

SOURCES:
Column b: Statement D, Schedule D-3, page 1 of 2, General Plant, account 389 - Land

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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. NG02-011

Testimony of Robert G. Towers
on Behalf of the Commission Staff

April 2003

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Montana-Dakota Utilities Co.
Application to Increase Gas Rates in South Dakota
Docket No. NG02-011

Testimony of Robert G. Towers
on Behalf of the Commission Staff

April 2003

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 thirteen 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 with MDU's 1993 and 1994 rate filings, Docket Nos. NG93-011 and NG94-012.

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. Were you retained to assist the Commission Staff in this case?

A. Yes.

Q. For what purpose were you retained?

A. CRC was retained, specifically, to address issues related to the Company's cost of capital and the allowable rate of return and issues raised by the class cost of service study sponsored by the Company's witness, Ms. Tamie Aberle. 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.

Q. How did you proceed?

A. My associate, Basil L. Copeland, Jr. assumed responsibility for assessing the Company's required return on common equity capital ("ROE") and weighted cost of capital. He is providing testimony recommending the required rate of return to be applied to the Company's South Dakota gas operations rate base

I have been responsible for analyzing the Company's class cost of service study and the related cost justifications offered in support of its proposed monthly customer Service Charges. I also assisted the Staff in reviewing various accounting issues entering into the determination of MDU's South Dakota revenue requirement. In that regard, I am presenting testimony on two issues including depreciation rates and expense and the appropriate allowance for Federal income taxes.

Q. Briefly, what are your conclusions and recommendations?

A. *Depreciation*
(See Exhibit___(RGT-1))

I have concluded that the depreciation accrual rates which the Company is using for two important accounts -- Account 376-Mains and Account 380-Services are excessive. The excess is attributable to the incorporation of speculative and unreasonable allowances for the removal costs that occur upon the retirement of plant that is presently in service. I recommend that the 4.18% rate which MDU uses for Account 376 be reduced to 3.68%. For Account 380 I recommend that the Company's rate be reduced from 8.22% to 6.38%. In each instance, the rate that I am recommending includes a substantial allowance for removal costs (or, more precisely, "net negative salvage") but at a lower level than the Company's rates reflect. Based on the average depreciable investments in these accounts during the year ended June 30, 2002, the accrual rates which I am recommending reduce the Company's annual depreciation expense by $180,178.

Federal Income Tax Allowance
(See Exhibit___(RGT-2)

The Company claims as an allowance for Federal income taxes an amount that is calculated as if it were an independent taxpayer. It is not. MDU, which is a division of MDU Resources, Inc. ("Resources"), is joined with Resources and its eligible subsidiaries in the filing of a consolidated Federal income tax return. This is advantageous because it allows the taxpayer (the Resources Group) to combine the ever-present taxable losses of some companies in the group with the taxable income of other members and thereby to pay a tax which is less than sum of the taxes which would be paid by the members with taxable income if they were to file separate tax returns. Using Resources experience during the three most recent years for which data are available, I calculate a consolidated tax savings adjustment reducing the tax allowance developed using the 35% statutory tax rate. The adjustment, allocated to MDU's South Dakota gas operations is a reduction of $218,593.

Class Cost of Service Study
(See Exhibit___(RGT-3))

I am in agreement with many aspects of the Company's cost study, but I disagree with its imputation of a "customer component" to distribution Mains. The Company 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 the class' contribution to the distribution system 2-Day Peak (64% weight). For a variety of reasons which I will discuss later, I believe that the Customer component is not justified. I therefore recommend that these costs be allocated among the classes entirely on the basis of peak demand requirements.

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. Indeed, my reallocation of the Company's cost of service shows that its proposed rates would result in a higher-than-average rate of return from Residential customers and a much lower-than-average return from Firm General service customers. Similar return relationships are indicated even with MDU's present rates. These results lead to my recommendation that the entire rate increase recommended by Staff (approximately $250,000) be assigned to the Firm General service class. An increase of this magnitude for Firm General service customers is significantly less than the $970,000 which MDU has proposed for this class.

Customer Service Charges
(See Exhibit___(RGT-4))

I find the Company's cost support for its 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 just 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.

In any event, my determination of the MDU's direct customer costs -- even as the Company projects them for the "Projected 2003" test year that it would use in this case -- is that they do not exceed the existing Service Charges for the largest classes (the Residential and Firm General service classes).

Prospectively, some upward pressure on these costs will occur if the Commission approves MDU's proposal to begin phasing in its ownership of the complete Service line to each customer.

III. Depreciation

Q. Has MDU presented a study in this case to justify the depreciation rates it uses?

A. No. The Company is using depreciation rates that it adopted in 1994 based on a study prepared by Stone & Webster of its plant and equipment at the end of 1991. A copy of the Stone & Webster report has been provided in this case as a Response to Staff Request No. 11

Q. Have you had an opportunity to review that study and, if so, do you agree that the depreciation rates adopted by MDU are appropriate?

A. I reviewed the Stone & Webster study and the testimony of the Stone & Webster engineer who sponsored it at the time MDU first proposed to revise its depreciation rates in gas rate cases in Montana (Montana PSC Case No. 94.4.17) and South Dakota (South Dakota PUC Case No. NG93-011). I critiqued the study in testimony in the Montana case and was prepared to file similar testimony in the South Dakota proceeding. However, the South Dakota case was settled without the submission of testimony by Commission Staff. I should point out that MDU's depreciation study encompassed collectively all of its gas distribution plant in all of the states in which it had such operations, including South Dakota, Montana, North Dakota and Wyoming.

For the reasons explained in my testimony in the Montana case, I continue to disagree with the conclusions and recommendations expressed in the Stone & Webster study on the issue of net salvage affecting the depreciation rates being used for two important plant accounts -- Account 376 - Distribution Mains and Account 380 - Services. It is my conclusion that the net salvage allowances which MDU is using for these accounts are neither appropriate nor are they necessary to provide for full recovery of its costs.

Q. What salvage estimates and depreciation rates is MDU using for these accounts?

A. For Mains, the Company proposes to use a rate of 4.18% reflecting a 40% net negative salvage allowance.

For Services, the Company proposes to use a rate of 8.22%, reflecting a 140% net negative salvage allowance.

Q. What is "net negative salvage"?

A. "Net negative salvage" describes the condition in which removal costs incurred at the time of a plant component's retirement exceeds the value of recovered materials. The factor (40% for Mains; 140% for Services) 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 year ended June 30, 2002 was $17.2 million. A 40% net negative salvage allowance implies that upon the retirement of this plant, the Company will incur $6.9 million of removal costs in excess of its scrap value. For Services, the 140% net negative salvage allowance implies a net removal cost of $7.1 million for the $5.1 million of its existing plant investment. The Company's depreciation rates are set to recover these amounts over the lives of the plant in each account.

Q. What rates and salvage allowances do you recommend for these accounts?

A. I recommend the rates which MDU used before it implemented its current rates. For Mains, that rate was 3.68% reflecting a 30% net negative salvage allowance. For Services, the rate was 6.38%, reflecting a 100% net negative salvage allowance.

For the two accounts, the rates that I recommend would reduce MDU's annual depreciation expense for the year ended June 30, 2002 by $180,178 (see Exhibit No.___(RGT-1), Schedule 1). This adjustment and a corresponding adjustment, reducing the depreciation reserve by one-half of this amount as if the reduced accrual rates had been implemented at the beginning of the year, are reflected in Staff witness Keith Senger's revenue requirement calculations.

Q. Why do you believe that the Company's increased net 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 existing plant and it is highly unlikely that the implied removal costs will be incurred.

The Stone & Webster analyses underlying MDU's 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 while the resulting depreciation rates are applied to investments in both the old and new plant.

Furthermore, the salvage experience studied by Stone & Webster 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 23-year period, 1968-91 was studied. During this time, the Company retired plant in which it had an investment of $4.5 million; this was less than one-tenth of the $52 million of Mains that were in service at the time the study was conducted. Moreover, the "retirements" included the $0.5 million sale of an operating system in Minnesota which should not have been considered a retirement unless it was expected to represent a recurring event.

Even more important than the aggregate amount of the retirements reviewed by Stone & Webster 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 produce economy of scale savings in removal costs.

The Stone & Webster report 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 studied, 1991, the Company's investment in gas distribution Mains was $52 million (the plant exposed to retirement) while actual retirements amounted to only $208,000. In the prior year, retirements were even less at $92,000. And, for the two years combined, experienced salvage amounted to only $3,000 while experienced removal costs amounted to $108,512 for all of MDU's gas distribution mains in South Dakota, North Dakota, Wyoming and Montana. To infer from $108,000 of experienced removal costs that MDU's ratepayers should be required to make annual contributions to offset future removal costs of more

than $20 million (40% of the $52 million of Mains in service at the time) was sheer speculation and inappropriate.

Q. How do the funds that would be generated by MDU's proposed net salvage allowances compare with net salvage that is concurrently experienced?

A. MDU's depreciable plant investment in Mains at the end of 1991 amounted to $51.9 million. The effect of the 40% net salvage allowance which it would use for this account, together with the adopted average service life establishes its proposed annual depreciation accrual rate of 4.18%. With zero net salvage (cost of removal equals salvage value) that rate would be 2.19%. The 1.99% difference between these rates applied to MDU's investment *in South Dakota Mains alone* in this case ($17,183,330) would generate a $341,900 annual allowance for the recovery of net negative salvage. This cash flow, from ratepayers to the Company, is more than three times the net removal costs actually incurred *in the entire four-state system* during 1991, the last year covered by the Stone & Webster study. Actual net negative salvage amounted to $66,574 in 1991 and ranged between $38,574 and $106,036 annually during the five year period, 1987-91[1]

Even at the rates that I am recommending, reflecting the net negative salvage allowances which MDU previously used – a negative 30% for Mains and a negative 100% for Services – the funds generated currently would greatly exceed the net negative salvage most recently experienced and reported in the Stone & Webster study. For Mains, the systemwide funds generated from a 30% negative salvage allowance would be 1.49% (3.68% - 2.19%) of depreciable plant investment, or $773,100 based on plant at the end of 1991. This is more than 10-times the average annual net negative salvage actually

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[1] For Services, the corresponding amounts are:

Investment @12/31/91 (4-state system)	$20.1 million	
Proposed by MDU - Net Salvage allowance	-140%	
Depreciation rate	8.22%	
Rate w/ Zero salvage	1.80%	
Difference (net salvage)	6.42%	
South Dakota investment - Year ended 6/30/02	$5,105,643	
Funds generated annually in South Dakota with MDU-proposed net salvage allowance		$327,782
Net negative salvage actually incurred on MDU's 4-state system:		
1991		$154,871
Range over 5-year period, 1987-91		$154,871 to $210,142

experienced over the five year period, 1987-91 ($72,679). For Services, my proposed 100% negative salvage allowance would generate annually 4.58% (6.38% - 1.80%), or $919,300 based on the year-end 1991 plant. This is more than 5-times the average annual net removal costs actually incurred over the most recent 5-year period in the study, 1987-91 ($175,459).

Q. Should the removal cost allowances be further reduced to better match the funds generated with current experience?

A. No, I do not recommend that here although some regulatory commissions have adopted that approach.

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 these conditions and events are not known with any level of confidence. Conditions under which future retirements will take place are continuously changing[2] and the expected service lives of utility plant are quite long. Thus, it is necessary to seek some guidance from the only remaining information -- current experience and/or historical relationships.

If, in retiring plant today, a company is incurring costs that are a significant percentage of the plant's original cost and one knows with certainty that all past events are likely to be repeated, the experience is instructive. On the other hand, 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 heavily discounted. This can be done by tempering the results of the statistical analysis of past retirements/removal costs with some consideration of the dollar level of removal costs actually being experienced. In general, I would be reluctant to recommend a removal cost allowance that generated fewer dollars currently than the removal costs actually being incurred.

Q. Have others recognized the difficulty of estimating future salvage and plant removal costs?

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[2] 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.

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.]

Q. Does MDU's system contain different pipe materials?

A. Yes. As indicated in Exhibit_(RGT-1), Schedule 2, page 1, plastic pipe has displaced steel pipe as the "material of choice" for both Mains and Services on MDU's system and, as explained on Schedule 2, page 2, MDU in 1986 embarked on a campaign to eliminate unprotected steel piping by 1999.

Q. What implications, if any, does this program have on the negative salvage issue that you raise in this case?

A. The salvage and cost of removal experience used in the Stone & Webster study is heavily weighted with the cost of removing steel piping. The adoption of

plastic pipe as the "material of choice" for new installations and replacements and the accelerated removal of steel pipe means that the composition of the investment to which the depreciation rate will be applied is shifting away from steel and toward plastic pipe. It should be obvious that the application of a removal cost estimate based on experience with steel pipe to an investment base representing primarily plastic pipe would be wrong, yet that is the effect of relying on the analyses in the Stone & Webster report.

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 3 and 4 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 removal costs that are likely to be incurred as plant is replaced.

Q. Doesn't the issue of intergenerational equity arise if ratepayers are not paying the removal cost related to the plant that they are using as they use it?

A. It does, but one need not agonize over a precise matching of these costs inasmuch as the decision to replace a main or service, giving rise to the removal cost, is often made to obtain a benefit for a future ratepayer, such as to increase delivery capacity, to improve pipeline safety or to reduce maintenance costs that otherwise would be incurred in the future. (see Exhibit___(RGT-1), Schedule 2, pages 5-6).

Q. You explained earlier that a depreciation rate is designed to allocate the cost of plant, adjusted for net salvage, over its useful life. Are there elements of the

depreciation rates other than the salvage and cost of removal allowances which might allow MDU to recover its investments in Mains and Services more quickly than is necessary?

A. Yes. The average service lives for both accounts are conservatively short based on the results of the Stone & Webster analyses and they are relatively shorter than the service lives reflected in the rates used by other companies for these investments.

For example, in Exhibit_(RGT-1), Schedule 2, page 7, MDU acknowledges that the 36-year average service life used for Mains is based on a statistical test yielding an indicated 37.30 years and that Stone & Webster's alternative analyses yielded service lives of 38 and 41 years. The same data response indicates that other gas utilities are using service lives averaging 49.7 years (North Central region) and 54 years (nationwide) for Mains. These data suggest that the 36-year life for Mains reflected in both MDU's proposed rate and my recommended rate for Mains may prove to be shorter than is necessary.

For Services, MDU indicates on page 8 of Schedule 2 that the adopted 34-year life is based on a statistical analysis suggesting a somewhat shorter 32.65 years. However, the Company also indicates that alternative analyses yielded service lives of 36 and 39 years and that the service lives used by gas utilities nationally (as reported by AGA/EEI) average 38.8 years.

I am not recommending the use of longer lives for these accounts based on these considerations; this is not warranted because, as I indicated earlier, the lives selected by Stone & Webster are reasonably supported by the consultant's statistical analyses of MDU's experience. Nevertheless, the experience of other companies and his alternative analyses of MDU's experience suggest that the selected lives may be increasing the depreciation rate above that which, ultimately, will prove to be required. If so, MDU's depreciation rates for these accounts will either recover the plant costs over a period shorter than the actual remaining life or provide a "cushion" which will offset any removal costs that are not explicitly provided for in the negative salvage allowances.

IV. Federal Income Taxes

Q. What does MDU claim as an allowance for Federal income taxes?

A. As explained by Ms. Mulkern (Testimony, page 8) and illustrated on page 7 of Statement K, the Company claims an allowance for currently payable Federal

income taxes that is the product of its projected test year taxable income and the currently-effective corporate tax rate of 35%.

Parenthetically, the amounts shown on page 7 of Statement K for the projected 2003 test year are negative because, without the proposed rate increase, the Company projects that it will have a taxable loss. With the proposed increase, the claimed allowance for current income taxes is $139,846, as shown on page 3 of Ms. Mulkern's Exhibit No.___(RAM-1).

Q. Does Montana-Dakota Utilities Co. actually file a tax return with the Internal Revenue Service?

A. No. Montana-Dakota Utilities Co. ("MDU") does not file a return with the IRS. MDU, which is a division of MDU Resources Group, Inc. ("Resources"), is joined with the remainder of Resources and with Resources' eligible subsidiaries in the filing of a consolidated Federal income tax return. This is illustrated on Schedule K-3 of Statement K for the year 2001 – the most recent year for which data were available when MDU made its rate filing.

Q. What are the ratemaking implications of the consolidated tax return filing?

A. If utility rates are to be based on costs that are actually incurred then it is imperative that the allowance for current Federal income taxes recognize any cost savings achieved through the filing of the consolidated tax return.

Q. Are tax savings realized by MDU Resources, Inc. through the filing of a consolidated tax return?

A. Yes. As Schedule K-3 shows, some participants in the consolidated return had taxable losses while others had taxable income in 2001. Reducing the combined taxable income of the companies with positive taxable income by the combined losses of the remaining companies, results in a consolidated tax liability that is less than the sum of the tax liabilities that would be incurred if those companies with positive taxable income filed individual returns.

MDU Resources, Inc. has minimized its corporate tax liability in this manner in each of the last three years, 1999 through 2001.

Q. What is the magnitude of these savings?

A. I prepared Exhibit No.___(RGT-2) to measure the savings and to allocate a portion of them to MDU and its gas operations in South Dakota. On page 2, for each year, 1999-2001, I tabulated the taxable income of participating companies with taxable income and the taxable losses of tax loss companies. The three years' experience is averaged and shows that MDU Resources was able to reduce the $158.6 million of taxable income generated by those companies with taxable income to a consolidated taxable income of $110.0 million. The reduction is achieved by using the $48.6 million of taxable losses generated by the remaining companies.

Based on its approximately 25 percent contribution to the taxable income of the income-generating companies, $12.4 million of this reduction in taxable income is allocable to Montana-Dakota Utilities which, at the present 35% Federal corporate tax rate, represents a tax savings of $4.3 million. As shown on page 1 of my exhibit, $218,593 of these savings are allocable to MDU's Gas operations in South Dakota.

Q. Is it not possible that some of the companies contributing tax losses might be able to carry-back or carry-forward those losses to other years?

A. Yes, but only if they filed their tax returns independently, i.e. a separate return. But that is not possible once the decision is made by Resources to file a consolidated return and, thereby, to take immediate advantage of tax losses as they are generated. Moreover, in utility ratemaking the relevant consideration is not whether certain companies regularly contribute tax losses that they could never utilize on a separate return basis but that such losses occur regularly within the group. The evidence here is clear that, at least in the last three years, there have been substantial losses within the MDU Resources Group, allowing it to minimize its tax payments.

Q. Is MDU exposed to any risk as a member of the Resources consolidated group?

A. Yes. Treasury Regulation 1.1502-6 provides that each member of a group filing a consolidated return is severally liable for the entire tax owed by the group. Thus MDU and its ratepayers could be encumbered with a liability much greater than the taxes that it would incur if filing a separate return.

Q. Have you given any special instructions to Mr. Senger as to how the consolidated tax savings adjustment should be applied to his determination of the revenue requirement?

A. Yes. I have indicated to him that the $218,593 adjustment should be used to reduce income taxes currently payable at the required revenue level. If taxes currently payable should be less than the adjustment, the applied adjustment should be capped at the level of taxes payable. That is, there should be no negative tax payable and there should be no reduction in deferred income taxes.

VI. 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 42 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 June 30, 2002, and the other reflecting its claimed Projected 2003 costs. The results are summarized on pages 6 and 7 (2002) and pages 4 and 5 (2003) of Part A of Statement N. The 2003 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 of $2,173,724.

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 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 seeking a $2.173 million increase in annual revenues based on its projected 2003 sales volumes -- a 5.8% rate increase in existing rate revenue, including the December 2002 Purchased Gas Cost Adjustment ("PGA") (Exhibit No.___(TAA-1). Because the cost study suggests that the return on rate base earned by all other classes exceeds the overall return which MDU says it requires, all of the increase is allocated to the Residential and Firm General service classes. The Company proposes to increase Residential rates by 5.8% with Firm General service rates up by 8.4%.

However, as I mentioned, these percentage increases represent, for each class, the impact of the proposed rate changes on the customers' total bills. But the proposed rate increase is unrelated to changes in the Company's gas supply costs and the filing proposes no change in the PGA portion of customers' bills through which such costs are recovered. A more meaningful assessment of the size of the rate increase requires comparing the proposed increase to the non-PGA portion of customer bills. This comparison indicates that the Company's proposal is for very substantial increases in the recovery of non-gas costs – about 13% for Residential customers and 15% for Firm General service customers.

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 a 2-day peak period.

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 allocated 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 as a source of gas supply -- not merely as a facility that exists merely for access.

Furthermore, unlike a meter, regulator and service line which are dedicated in their entirety to a 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-3), Schedule 4, pages 1-2). This hypothetical system is the length of MDU's distribution systems (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 relationship of pipe size to cost. The zero intercept purports to represent the theoretical cost of a Main with no capacity. As indicated at the bottom of page 2 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 (35.8% of the total Mains investment).

But any number of greatly varying results could be obtained from MDU's data. 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 plastic pipe cost (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 the time of the Stone & Webster depreciation study which I referred to earlier in my testimony, some of the surviving Mains had been installed as early as 1944. Obviously, the system was built in response to changing requirements *as the needs arose*; it is not necessarily the "minimum system" that would be required merely to connect now-existing customers to the system.

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 2-Day Peak that is the second component of the Company's allocator.

Q. How does the change in allocations that you are proposing affect the cost of service by rate class?

A. Schedule 3 of Exhibit___ (RGT-3) is a recalculation of the Projected 2003 class cost of service study presented by Ms. Aberle and summarized in Statement N, Part A, on page 4. The recalculation reflects only one change in MDU's calculations – use of the 2-day Peak factor to allocate Mains in place of the composite factor 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 3 matches the corresponding column in Ms. Aberle's cost study; both indicate an overall rate of return earned of 2.381% 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	2.073%	4.213%
Firm General	(1.376)	(4.012)
Firm Contract	85.366	51.113
Air Force	65.914	65.914
Small Interruptible	25.454	20.772
Large Interruptible	33.399	21.469

The implications of these returns are two-fold. First, the effect of the allocation change on Firm Contract and Air Force customers as well as the Small and Large Interruptible users is not significant. Both allocation methods indicate that existing rates applicable to these customers should not be increased. Specific rate components may require adjustment, but there is no need for a general rate increase to these customers because the rates of return are well above the required level measured by any party's rate of return recommendation and because Staff's lower revenue requirement determination would serve only to increase the calculated rates of return.

Second, the end result of the allocation method that I propose is a shift in costs away from the Residential class and to *all other classes* (except the Air Force). Most significantly affected is the Firm General service class.

Q. Incidentally, Mr. Towers, does your use of the Company's Projected 2003 cost study reflect your endorsement of that period as a test year or of the overall revenue requirement developed by the Company?

A. No. I have used the Company's cost of service study to illustrate the differences between our allocations without confusing the allocation changes with the effects of the test year selection or the level of costs reflected in the Staff and Company determinations of revenue requirements. Staff is using a test year based on actual operating results for the year ended June 30, 2002, adjusted for known and measurable changes and has made an independent determination of the required rate increase.

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 $2,173,118 by first increasing the Firm General service customers rates to produce the 10.3% overall rate of return it is claiming. Residential customers are allocated the remainder. I prepared two calculations to show the effect of this distribution on the class rates of return reflecting both MDU's allocation method and the method that I recommend. Exhibit___(RGT-3), Schedule 2, page 1 reflects the Company's allocation method and shows, as Ms. Aberle explained, that its distribution of the rate increase resulted in a rate of return for the Firm General service class that closely matches the overall rate of return. Page 2 of Schedule 2, reflecting my allocation method, shows however that the Company's distribution of the rate increase achieves only a 5.96% rate of return from this class but that its revenue distribution raises the Residential rate of return well above the 10.3% overall objective return.

Similar results are indicated on Schedule 1 of Exhibit___(RGT-3) for the unadjusted year ended June 30, 2002 and reflecting my allocations.[3] This is the period which is the starting point for Staff's determination of MDU's revenue requirement, summarized in Mr. Senger's presentation.

Q. Given these results, how should the revenue increase recommended by Staff be allocated among the classes?

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[3] The corresponding calculation reflecting the Company's allocations can be found on page 6, Part A of Statement N.

A. Schedule 1 of Exhibit___(RGT-3) shows that, while the return earned from Residential customers with present rates (7.177%) is about ten percent above the system average (6.594%), the Firm General service class return is negative. As in the other (2003) analyses, other classes are shown to produce returns that are much higher than average. I therefore recommend assigning the entire rate increase recommended by Staff to the Firm General service class. This will reduce the difference between the returns earned from the Residential and Firm General service classes but will not eliminate it. An increase of $250,000 to the Firm General service class would raise the class return to a positive 1%, still well below the 7.2% Residential class return and the overall return of 6.6%.

As I mentioned earlier, a $250,000 rate increase to the Firm General service class is substantially less than the $970,000 which MDU proposes for this class.

VII. Customer Service Charges

Q. What changes has the Company proposed in its monthly customer Service Charges?

A. The Company proposes to establish a "Basic Service Charge" applicable to each customer class that is "closer to the customer cost level identified in the Class Cost of Service Study". (Aberle testimony, page 6). Also, it proposes to convert the Service Charge from a uniform monthly charge to a daily charge to reflect any variations in the length of the billing period. Mr. Bettmann will address the latter change. For Residential customers with small meters (the dominant service condition), the Company would increase the present monthly "Base Rate" by 82%, from $7.00 to a per day Basic Service Charge of $0.42, equivalent to an average monthly charge of $12.77.

For Firm General service customers with small meters, the corresponding increase is from a monthly charge of $7.50 to a per day charge of $0.90, equivalent to an average monthly charge of $27.37 -- an increase of 260%. For Firm General service customer with large meters, the increase is the same 260% – $15.00 to a monthly equivalent of $54.72.

Q. Are these charges cost-justified?

A. No. The purported cost justification for the proposed Service Charges is found on pages 1 through 3 of Part A of MDU's filing Statement N. 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 classes. The cost per customer per month for Residential customers of $16.046 is the Company's justification for the proposed charge of $12.77. Similarly, the $39.285 cost per customer is said to justify the $27.37 and $54.72 monthly charges to Firm General service customers.

The "Customer" costs are greatly overstated. In addition to the fact that the costs are based on all of the Company's Projected 2003 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 an 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, Mains should not be regarded as a "customer cost" to be considered 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 commodity 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-4) shows my determination of these costs for each class based on the Company's Projected 2003 class cost of service study, as modified to reflect my allocation of Mains in Exhibit___(RGT-3).

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-4) 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?

A. By focusing on the costs that are directly related to maintaining customer service, my determinations indicate customer costs for Residential customers of $6.08 per customer per month, as compared to the $16.046 cost claimed by the Company. Similarly, my determination for the Firm General service customers is $17.48, down from the Company's claimed $39.285.

Q. How do your determinations of customer costs compare with the customer service charges that are presently in effect?

A. For the Residential class, my cost determination ($6.08) is somewhat less than the presently-effective rate ($7.00), suggesting that no increase is necessary. The same conclusion can be drawn from a comparison of costs in the Firm General service class.

Q. I have no further questions at this time, Mr. Towers.

Exhibit No.___(RGT-1)
Schedule 1
SDPUC Docket No.NG02-011

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Adjustment to Depreciation Expense to Reflect Staff-Proposed Depreciation Rates
for Mains and Services
Year Ended June 30, 2002

Account (A)	Average Depreciable Plant (B)	Depreciation Rate & Salvage Allowance: Claimed by MDU (C)	Depreciation Rate & Salvage Allowance: W/ Reduced Net Negative Salvage (D)	Annual Depreciation Expense: MDU Claimed Rates (E)	Annual Depreciation Expense: Staff Proposed Rates (F)	Annual Depreciation Expense: Impact (G)
Account 376 - Mains	$17,208,291	4.18 -40%	3.68 -30%	$719,307	$633,265	($86,041)
Account 380 - Services	$5,116,102	8.22 -140%	6.38 -100%	$420,544	$326,407	($94,136)
Total	$22,324,393			$1,139,850	$959,672	($180,178)

Sources: Statement D, Schedule D-3, page 1
Response to Staff Request No. 11

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 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.

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. 15: Explain the large difference between the average service lives for Accounts 376 - Mains estimated by other utilities and reported in the above referenced AGA/EEI statistical report and the 35 year life estimated by MDU.

Response: The 36 year service life recommended for Account 376-Mains is based on simulated plant balance tests, particularly the tests utilizing the most recent 20 and 30 years of balances. The precise first-in-first-out turnover for the account is 37.30 years.

The two closest runner-up service lives, for Iowa Curves R3 and R4 are 41 and 38 years, respectively.

The average service life for mains in the U.S. (1991-92 AGA/EEI survey) is 54 years. The North Central region average is 49.7 years.

The average of the longest-lived ten accounts is 75 years. The average of the shortest-lived ten accounts is 32.4 years. Obviously there are wide variations, based on a variety of unique factors. The recommended service life of 36 years for Montana-Dakota is based on standard testing procedures using company data, not industry averages.

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. 16: Explain why MDU experience allegedly indicates an average service life for Account 380 - Services of only 34 years while other gas companies are claiming to experience average service lives in the range of 40 to 50 years for the same plant.

Response: The 34 year service life recommended for Account 380-Services is based on simulated plant balance tests, particularly the tests utilizing the most recent 20 and 30 years of balances. The precise first-in-first-out turnover for the account is 32.65 years.

The two closest runner-up service lives, for Iowa Curves R2 and R2.5 are 39 years and 36 years, respectively.

The average service life for services in the U.S. (1991-92 AGA/EEI survey) is 38.8 years. Other gas companies are reporting service lives from the high 50's to the mid-20's, a wide range. The data presented by the survey represents approved lives, not merely claims. All of them may be presumed to be based on a variety of unique factors. The 34 years recommended for Montana-Dakota is based on standard testing procedures using company data.

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Consolidated Federal Income Tax Savings

	(A)	(B)	(C)	(D)	(E)
1	1999-2001 average taxable losses used to reduce the consolidated taxable income of MDU Resources Group, Inc.	$48,652,186			
2	Allocated to Montana-Dakota Utilities Co.	$12,356,205			
3	Consolidated tax savings @35%	$4,324,672			
			Taxable Income Y.E. 6/30/02		Consolidated Tax
			Amount	Ratio	Savings
	Allocation to operations:				
4	Gas utility		$8,609,271	0.201393	$870,957
5	Electric utility		$33,283,997	0.778597	$3,367,176
6	Non-utility		$855,421	0.020010	$86,539
7	Total		$42,748,689	1.000000	$4,324,672
	Allocation to Gas utility - South Dakota				
8	Total Gas utility		$8,609,271	1.000000	
9	South Dakota		$2,160,760	0.250981	$218,593

Sources:
Column B: Lines 1-2 - Page 2
Column C: Statement K, pages 1 and 4

Allocation of Taxable Losses Used to Reduce Consolidated Tax Liability
of MDU Resources Group

Participating Companies	1999 Number	1999 Taxable Income(Loss)	2000 Number	2000 Taxable Income(Loss)	2001 Number	2001 Taxable Income(Loss)	Averages	Ratios	Allocation of Avg.Taxable Losses
Companies with taxable income									
Rate-regulated									
MDU	1	$36,893,019	1	$35,915,090	1	$48,062,511	$40,290,207	0.253970	($12,356,205)
Williston Basin Interstate	1	$11,007,753	1	$13,348,491	1	$29,137,835	$17,831,360	0.112400	($5,468,523)
Unregulated companies	29	$66,810,234	35	$75,679,781	43	$159,069,713	$100,519,909	0.633629	($30,827,458)
Total w/taxable income	31	$114,711,006	37	$124,943,362	45	$236,270,059	$158,641,476	1.000000	($48,652,186)
Companies with taxable losses	12	($30,396,945)	15	($56,119,283)	14	($59,440,331)	($48,652,186)		
Consolidated	43	$84,314,061	52	$68,824,079	59	$176,829,728	$109,989,289		

Sources: Response to Staff Data Request No. 18
Statement K, Schedule K-3

Exhibit No.___(RGT-3)
Schedule 1
SD PUC Docket No. NG02-011

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
EMBEDDED CLASS COST OF SERVICE STUDY
SUMMARY REPORT
TWELVE MONTHS ENDED JUNE 30, 2002

Reflecting Class Cost of Service Allocations per Staff

Per Books Operating Income and Rate of Return	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
Operating Revenues - Present rates	$31,494,700	$17,173,625	$9,447,587	$2,664,977	$1,353,999	$430,289	$424,223
Operating Expenses							
Cost of Gas	21,351,949	10,383,254	7,087,808	2,230,621	1,327,230	127,717	195,319
Other O&M Expense	6,262,743	4,307,266	1,759,424	41,925	11,995	86,376	55,757
Total Operation & Maint. Exp.	27,614,692	14,690,520	8,847,232	2,272,546	1,339,225	214,093	251,076
Depreciation	1,607,619	971,308	577,209	16,304	869	25,570	16,359
Taxes Other Than Income Taxes	719,994	461,622	232,585	6,537	980	10,647	7,623
Fed. & State Inc. Taxes - Current	546,057	353,287	(77,082)	143,308	13,694	61,348	51,502
Deferred Income Taxes	(107,216)	(34,389)	(29,313)	(27,067)	(17,261)	1,129	(315)
Total Operating Expenses	30,381,146	16,442,348	9,550,631	2,411,628	1,337,507	312,787	326,245
Operating Income	1,113,554	731,277	(103,044)	253,349	16,492	117,502	97,978
Rate Base	16,886,220	10,188,783	5,992,657	187,014	20,204	278,399	219,163
Rate of Return	6.594%	7.177%	-1.720%	135.471%	81.627%	42.206%	44.706%

MONTANA-DAKOTA UTILITIES CO.

Gas Utility - South Dakota
Analysis of MDU's Proposed Spread of Requested Increase
Reflecting Class Cost of Service Allocations per MDU
Projected 2003

Exhibit No.___(RGT-3)
Schedule 2
Page 1 of 2
SDPUC Docket No. NG02-011

Item (A)	South Dakota (B)	Residential ©	Firm General (D)	Firm Contract (E)	Air Force (F)	Small Interruptible (G)	Large Interruptible (H)
1. Rate base per MDU cost study	$17,793,766	$11,802,624	$5,397,473	$132,672	$20,979	$261,934	$178,084
2. Operating income with present rates	423,630	244,686	(74,292)	113,257	13,828	66,673	59,478
Rate of return earned	2.381%	2.073%	-1.376%	85.366%	65.914%	25.454%	33.399%
3. MDU proposed revenue increase	$2,173,380	$1,201,617	$971,351	$0	$150	$182	$80
4. FIT & other taxes @ 35.15%	763,943	422,368	341,430	0	53	64	28
5. *Additional income produced by increase*	1,409,437	779,249	629,921	0	97	118	52
6. Operating income at MDU proposed rates	$1,833,067	$1,023,935	$555,629	$113,257	$13,925	$66,791	$59,530
7. Rate of return at proposed rates	10.30%	**8.68%**	**10.29%**	85.37%	66.38%	25.50%	33.43%

MONTANA-DAKOTA UTILITIES CO.

Gas Utility - South Dakota
Analysis of MDU's Proposed Spread of Requested Increase
Reflecting Class Cost of Service Allocations per Staff
Projected 2003

Exhibit No.___(RGT-3)
Schedule 2
Page 2 of 2
SD PUC Docket No. NG02-011

Item	Total South Dakota	Residential	Firm General	Firm Contract	Air Force	Small Interruptible	Large Interruptible
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1 Rate base per Staff cost study	$17,793,767	$10,737,105	$6,316,320	$197,021	$20,979	$292,391	$229,951
2 Operating income with present rates	423,630	452,393	(253,399)	100,704	13,828	60,736	49,368
3 Rate of return earned	2.381%	4.213%	-4.012%	51.113%	65.914%	20.772%	21.469%
4 MDU-proposed revenue increases	$2,173,380	$1,201,617	$971,351	$0	$150	$182	$80
5 FIT & other taxes @ 35.15%	763,943	422,368	341,430	0	53	64	28
6 Additional income produced by increase	$1,409,437	$779,249	$629,921	$0	$97	$118	$52
7 Operating income at MDU-proposed rates	$1,833,067	$1,231,642	$376,522	$100,704	$13,925	$60,854	$49,420
8 Rate of return earned @ proposed rates	10.30%	**11.47%**	**5.96%**	51.11%	66.38%	20.81%	21.49%

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-4)
SDPUC Docket No. NG02-011

MONTANA-DAKOTA UTILITIES CO.

Gas Utility - South Dakota
Customer Cost Analysis
Projected 2003

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	$505,226	$280,111			$27,598	$9,125
2. Indust. Meas. & Reg. Sta. Eqpt.	0	0			7,846	55,583
3. Services	3,306,619	1,800,876			123,995	0
4. Meters	3,666,640	1,996,953	$14,025		137,495	0
5. Total customer plant in service	$7,478,485	$4,077,940	$14,025	$0	$296,934	$64,708
6. Accumulated depreciation	(4,672,518)	(2,546,746)	0	0	(181,134)	(21,238)
7. Accumulated deferred income taxes	(300,896)	(164,038)	(564)	0	(11,946)	(2,604)
8. Accumulated investment tax credits	(3,308)	(1,776)	(6)	0	(131)	(29)
9. Customer advances for construction	(5,332)	(17,385)	0	0	0	0
10. Customer-related net plant	$2,496,431	$1,347,995	$13,455	$0	$103,723	$40,837
Customer-related cost of service						
11. Rate of return @ 10.394%	259,479	140,111	1,399	0	10,781	4,245
12. Income taxes on return	85,937	46,403	463	0	3,571	1,406
Operating expenses						
13. Services	105,269	57,331	0	0	3,948	0
14. Measuring stations - Industrial					729	5,167
15. Meters and house regulators	151,439	82,658	509	0	5,993	331
16. Customer installations	275,044	149,797	0	0	10,314	0
Maintenance expenses						
17. Measuring stations - Industrial					572	4,052
18. Services	18,247	9,859	60	0	630	537
19. Meters and house regulators	26,845	14,652	90	0	1,062	59
20. Customer accounts	71,134	9,685	2	2	83	22
21. Meter reading	166,486	90,673	0	0	6,243	0
22. Customer records & collection	637,040	86,737	18	18	747	196
23. Miscellaneous customer accounts	81,455	11,091	2	2	95	25
24. Customer service & information	55,978	7,622	2	2	66	17
25. Employee pensions and benefits	255,447	84,518	89	4	4,983	
26. Depreciation expense	369,343	201,270	0	0	14,203	1,275
27. Property taxes	56,856	31,161	286	0	2,248	826
28. Customer-related cost of service	$2,615,999	$1,023,568	$2,920	$28	$66,268	$18,158
29. Number of annual bills	430,092	58,560	12	12	540	168
30. Customer cost per bill	$6.08	$17.48	$243.33	$2.33	$122.72	$108.08

STATEMENT OF EDUCATION AND EXPERIENCE

ROBERT G. TOWERS
Senior Consultant
Chesapeake Regulatory Consultants, Inc.
6837 Guilford Road
Clarksville, MD 21029-1632
443.535.0300
FAX: 443.535.0301

Mr. Towers is President of Chesapeake Regulatory Consultants, Inc. Over the past forty years he has assisted clients in dealing with a wide range of ratemaking policy, accounting, financial, economic and operational issues affecting rates and services offered by all types of utilities. He has testified in more than 200 public utility rate proceedings before regulatory commissions in 28 states and the District of Columbia, the Federal Energy Regulatory Commission and its predecessor the Federal Power Commission.

EMPLOYMENT

1986 - Present	President and Senior Consultant Chesapeake Regulatory Consultants, Inc. Columbia, Maryland
1970 - 1986	Vice President and Senior Consultant Hess & Lim, Inc. Greenbelt, Maryland
1960 - 1970	Consultant Martin Toscan Bennett Associates Washington, D.C.

As a consultant with each of the firms listed above, Mr. Towers participated extensively in wholesale and retail rate proceedings before federal and state regulatory agencies on behalf of the firms' clients. His participation has involved analyses of a broad range of ratemaking concepts, and specific accounting, financial, operational, allocation and rate design issues raised by the utility's rate filings or in client complaints. Specific tasks included analyses of the utility's operations and filed financial data, assistance with discovery and cross-examination, presentation of affirmative testimony, assistance with the preparation of legal briefs and other pleadings, and assistance in settlement negotiations. The subject utilities have included electric, gas, steam and water distribution companies; electric generating utilities; gas and products pipeline companies; waste water systems; transit companies; and telecommunication companies.

Clients served by Mr. Towers have included numerous state regulatory commissions and their staffs; consumer advocate agencies of state governments; federal government agencies as consumers of utility services; municipalities as consumers of utility services and as representatives of their citizens; municipal agencies; municipally-owned and cooperative utility systems; civic organizations; industrial consumers; and investor-owned utilities, principally as purchasers of utility services from other investor-owned companies.

EDUCATION

June 1960 Bachelor of Science Degree in Economics
University of Maryland
College Park, Maryland
Phi Eta Sigma and
Phi Kappa Phi Honor Societies

PROFESSIONAL ORGANIZATIONS

American Economic Association
American Water Works Association

PUBLICATIONS & SPECIAL APPEARANCES

Article "Cost of Debt Capital in Allowed Rates of Return" published in Public Utilities Fortnightly, Vol. 68, No. 1.

Paper "Ratemaking Consideration of Construction Work in Progress" presented to the Conference of State Utility Consumer Advocates, University of Chicago, June 1979.

Paper on CWIP treatment presented to the Iowa State Regulatory Conference, Iowa State University, May 1980.

EXPERT TESTIMONY

Mr. Towers has presented testimony to the following regulatory authorities in more than 200 proceedings.

Arkansas Public Service Commission
Connecticut Public Utilities Control Authority
Colorado Public Utilities Commission
Delaware Public Service Commission
District of Columbia Public Service Commission

Florida Public Service Commission
Hawaii Public Utilities Commission
Idaho Public Utilities Commission
Iowa Public Utilities Board
Maryland Public Service Commission

Massachusetts Department of Public Utilities
Minnesota Public Utilities Commission
Mississippi Public Service Commission
Montana Public Service Commission
Nevada Public Service Commission

New Mexico Public Service Commission
New York Public Service Commission
Ohio Public Utilities Commission
Pennsylvania Public Utility Commission
Rhode Island Public Utilities Commission

South Dakota Public Utilities Commission
Texas Public Utility Commission
Texas Railroad Commission
Utah Public Service Commission
Vermont Public Service Board

Virginia State Corporation Commission
Washington Utilities and Transportation Commission
West Virginia Public Service Commission
Wisconsin Public Service Commission
Wyoming Public Service Commission

Federal Energy Regulatory Commission
Federal Power Commission

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BRETT KOENECKE

OF COUNSEL
WARREN W. MAY

GLENN W. MARTENS 1881-1963
KARL GOLDSMITH 1885-1966

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April 30, 2003

RECEIVED
APR 30 2003
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

HAND DELIVERED

Pam Bonrud, Executive Secretary
Public Utilities Commission
500 East Capitol Avenue
Pierre, South Dakota 57501

RE: **IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE**
Docket: NG02-011
Our file: 4165

Dear Pam:

Enclosed are original and ten copies of a motion to continue the hearing and the procedural schedule in this matter. Please file the enclosure.

With a copy of this letter, I am sending copies of the enclosure to the service list.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

DAVID A. GERDES

DAG:mw

Enclosures

cc: Karen Cremer
Dave Jacobson
Don Ball
Rita Mulkern

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	))))	NG02-011

RECEIVED
APR 30 2003
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

MDU'S MOTION TO CONTINUE AND
RESCHEDULE THE HEARING

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) moves the Commission to continue the hearing of May 7 and 8, 2003, scheduled in this matter and set a new hearing date and procedural schedule.

The justification for this motion is based upon the proposition that MDU has several simultaneous regulatory matters proceeding at the present time and the procedural schedule established by the Commission does not now permit MDU to properly prepare its rebuttal case according to the timeline established in the procedural schedule. Notwithstanding that MDU agreed to the procedural schedule several months ago, the unforeseen confluence of several matters occupying the time of MDU staff requires this request. Additionally, MDU cannot explore avenues of potential settlement with staff until after its rebuttal case has been completed.

WHEREFORE MDU prays that the Commission continue the hearing set for May 7 and 8, 2003, in this matter and reestablish a procedural schedule in accordance with the relative positions of the parties.

Dated this 30 day of April, 2003.

MAY, ADAM, GERDES & THOMPSON LLP

BY: _____

DAVID A. GERDES
Attorneys for MDU
503 South Pierre Street
P.O. Box 160
Pierre, South Dakota 57501-0160
Telephone: (605)224-8803
Telefax: (605)224-6289

CERTIFICATE OF SERVICE

David A. Gerdes of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 30 day of April, 2003, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, to-wit:

Karen Cremer
Staff Attorney
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, SD 57501-5070

Dave Jacobson
Staff Analyst
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, SD 57501-5070

David A. Gerdes

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May 7, 2003

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

HAND DELIVERED

Pam Bonrud, Executive Secretary
Public Utilities Commission
500 East Capitol Avenue
Pierre, South Dakota 57501

RE: **IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE**
Docket: NG02-011
Our file: 4165

Dear Executive Secretary Bonrud:

Enclosed are original and ten copies of MDU's Interrogatories and Requests for Production. Please file the enclosure.

With a copy of this letter, I am sending copies of the enclosure to Commission Staff.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

DAVID A. GERDES

DAG:mw

Enclosures

cc/enc: Karen Cremer
Dave Jacobson
Don Ball
Rita Mulkern

RECEIVED

MAY 07 2003

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF	)	NG02-011
MONTANA-DAKOTA UTILITIES CO. FOR	)	
AUTHORITY TO INCREASE RATES FOR	)	
NATURAL GAS SERVICE	)	

MDU'S INTERROGATORIES AND REQUESTS
FOR PRODUCTION TO COMMISSION STAFF

Pursuant to ARSD 20:10:01:22.01 and the South Dakota Rules of Civil Procedure ("SDRCP") Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., ("MDU") submits the following interrogatories and requests for production to Commission Staff. These interrogatories and requests for production are collectively referred to as requests for discovery.

In these requests for discovery, where knowledge or information in the possession of a party is requested, the request includes knowledge of the party's agents, representatives and attorneys. A request for the location of documents constitutes a request for the present address at which such documents are kept, if known, and if not known, the last address known and information as to their disposition. A request for production of documents includes a request for all components of the original document, and a request for all documents and their components within the category requested. "Custodian" means the person who has possession or control of documents, and a request for the identity of a custodian constitutes a request for the name, telephone number and present address of the custodian.

"Identify" with respect to documents, means to state the date, title, subject matter, custodian and author of a document. "Identify" as to persons, means the name, address, telephone number and occupation of the person to which reference is made. These requests for discovery shall be deemed continuing so as to require seasonable supplemental answers if you or your agents, representatives or attorneys, obtain further information between the time answers are served and the time of final disposition of this proceeding.

INTERROGATORIES AND REQUESTS FOR PRODUCTION

You are hereby requested to answer the following interrogatories in the time and in the manner specified by SDRCP 33 and 36.

Attached hereto are Interrogatories and Requests for Production numbered 1 through 46, inclusive, which are incorporated herein by this reference.

Dated this 7 day of May, 2003.

MAY, ADAM, GERDES & THOMPSON LLP

BY: _____
DAVID A. GERDES
Attorneys for MDU
503 South Pierre Street
P.O. Box 160
Pierre, South Dakota 57501-0160
Telephone: (605)224-8803
Telefax: (605)224-6289

CERTIFICATE OF SERVICE

David A. Gerdes of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 7 day of May, 2003, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, to-wit:

Karen Cremer, Staff Attorney
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, SD 57501-5070

Dave Jacobson, Staff Analyst
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, SD 57501-5070

_____
David A. Gerdes

MONTANA-DAKOTA UTILITIES CO.
DATA REQUESTS TO THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF
DATED APRIL 29, 2003
DOCKET NO. NG02-011

Basil L. Copeland

1. Provide the workpapers that support the capital ratios and costs shown on Exhibit ___(BLC-1), Schedule 1.

2. Please provide all workpapers, that are not otherwise provided in response to a specific data request hereafter, and that were generated by (or on behalf of, or at the direction of) Witness Copeland in his analyses in this proceeding. This request covers the written Testimony and the accompanying exhibit. This request is intended to cover both (a) workpapers, generated by or on behalf of, but not relied upon by, Witness Copeland and (b) workpapers that were generated by or on behalf of, but that are not favorable to or consistent with the filed testimony presented by, Witness Copeland. Label all of the contents of such workpapers so that each of their links to the Testimony and/or exhibit is readily ascertainable.

3. Refer to lines 18-23 of page 2 of the Testimony. For each "proceeding" of the "150 proceedings" cited therein that have occurred within the last 5 years, please provide a full copy of the resulting testimony, irrespective of whether such testimony was sponsored by Witness Copeland. In so responding, please give separate response numbers, labels or other clear designations [e.g., (i), (ii), etc.] for each separate proceeding within the last 5 years.

4. Referring to the Testimony from page 2, lines 18-23, in the current belief of Witness Copeland, in which other proceedings has Witness Copeland employed general or detailed analytic methodologies, in rate of return testimony, that differ from the methodologies contained in the current Testimony? For each such instance, describe in detail all the analytic and subjective factors responsible for using a different methodology, in such other proceedings by Witness Copeland. Furnish all explanatory and support materials relative to the instances that are pertinent hereto and are not provided in response to another data request herein.

5. Referring to the Testimony from page 2, lines 18-23, in which other proceedings, if any, has any witness who testified on behalf of the South Dakota commission or its staff employed general or detailed analytic methodologies, in rate of return testimony, that differ from the methodologies contained in the current Testimony? For each such instance, describe in detail all the analytic and subjective factors responsible for using a different methodology, in such other proceedings by Witness Copeland. Furnish all explanatory and support materials relative to the instances that are responsive hereto, including testimony copies, data request response, hearing transcripts, workpapers, etc.

6. Referring to the Testimony at page 6, lines 5-8, define the phrases "the same kind of incentive" and "competitive unregulated firm" as used therein. Provide all of the

copies of and/or citations to economic literature, data, empirical studies, specific tests, analytic criteria, and/or other bases relied upon by Witness Copeland, that support this cited conclusion. To the extent that each relevant nexus between (a) every such supplied item and (b) the conclusion of the witness is not readily ascertainable from the face of such materials, provide a detailed explanation of how such materials support the conclusions of Witness Copeland.

7. Referring to the Testimony at page 8, lines 6-8, provide all citations to economic literature upon which Witness Copeland relied to reach that conclusion. Does Witness Copeland recall reading any materials, throughout his career, that supported a different conclusion? Provide citations or copies of all regulatory decisions, in any jurisdiction, that support the Testimony conclusions cited therein. Provide citations or copies of all regulatory decisions, in any jurisdictions, that would support a different conclusion than that contained in the Testimony. Have there been any other proceedings in which Witness Copeland has ever departed from the cited standard? For each such case, describe in detail all of the analytic and subjective factors responsible for that different methodology decision by Witness Copeland. Furnish all explanatory and support materials relative to the instances that are responsive hereto.

8. Referring to the Testimony at page 8, lines 10-11, by what specific criteria has Witness Copeland determined that this particular methodology is accurate for these specific factual circumstances of MDU? Provide all copies of or citations to economic literature, data, empirical studies, specific tests, analytic criteria, and/or other bases that were relied upon by Witness Copeland to reach that conclusion. To the extent that each relevant nexus between (a) every such supplied item and (b) the conclusion of the witness is not readily ascertainable from the face of such materials, provide a detailed explanation of how such materials support the conclusions of Witness Copeland.

9. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1977 "Double Leverage [...etc.]" article cited therein:

   (a) Provide a full copy of such article; and,

   (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

10. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1978 "Alternative Cost of Capital [...etc.]" article cited therein:

   (a) Provide a full copy of such article; and,

(b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

11. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1979 "Estimates of the Cost of Capital [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

12. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1979 "The Cost of Equity Capital [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

13. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1981 "Capacity Planning [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

14. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the award winning 1982 article entitled "Inflation, Interest Rates and Equity Risk Premium" cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

15. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1983 "Do Stock Prices [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

MONTANA-DAKOTA UTILITIES CO.
DATA REQUESTS TO THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF
DATED APRIL 29, 2003
DOCKET NO. NG02-011

16. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1984 "Inflation, Monetary Policy [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

17. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1984 "Ratemaking Treatment [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

18. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1985 "Bailing Out [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

19. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1985 "Price Theory [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

20. Refer the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1987 "Capital Gains Taxes [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

21. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1989 "Escape from the Black Hole of FERC [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

(b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

22. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1989 "Telecommunications Regulation [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

23. Refer to the "Publications" listing appearing after page 18 of the Testimony. With respect to the 1991 "Procedural vs. Substantive Economic Due Process [...etc.]" article cited therein:

    (a) Provide a full copy of such article; and,

    (b) Does Witness Copeland know of any errors in such article? If so, describe and explain fully.

24. Referring to Witness Exhibit (BLC-1), Schedule 1, to the extent not otherwise furnished in response to other requests herein, provide excerpted copies of all original source materials and workpapers that support each of the entries on this schedule. Label all of the workpapers so that their link to each of the schedule data entries is readily ascertainable.

25. Referring to Witness Exhibit (BLC-1), Schedule 2, provide excerpted copies of all original source materials and workpapers that support each of the entries on this schedule. Label all of the workpapers so that their link to each of the schedule data entries is readily ascertainable.

26. Referring to Witness Exhibit (BLC-1), Schedule 3, provide excerpted copies of all original source materials and workpapers that support each of the entries on this schedule. Label all of the workpapers so that their link to each of the schedule data entries is readily ascertainable.

27. Referring to Witness Exhibit (BLC-1), Schedule 4, provide excerpted copies of all original source materials and workpapers that support each of the entries on this schedule. Label all of the workpapers so that their link to each of the schedule data entries is readily ascertainable.

28. Does Witness Copeland know of any errors in his Testimony and Exhibit? Provide a detailed explanation of the nature of and reason(s) for such errors, and provide the corrections thereto.

MONTANA-DAKOTA UTILITIES CO.
DATA REQUESTS TO THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF
DATED APRIL 29, 2003
DOCKET NO. NG02-011

29. Furnish copies of all papers or speeches, authored or delivered by Witness Copeland in the last 5 years, that address energy regulatory matters.

Martin Bettmann

30. At page 9 of his direct testimony, Mr. Bettmann discusses his concerns with the Company's proposed DDSM mechanism. Specifically, at lines 18-21, he states that, "It is also possible that due to variations in the weather in different parts of the Company's service area, customers in one area maybe experiencing a colder or warmer heating season than in other areas and therefore those customers could receive or pay an unfair share of the DDSM adjustment." Please provide all studies or any other information relied upon by Mr. Bettmann to support this contention.

31. At page 9, lines 24-26 of his direct testimony, Mr. Bettmann contends that one other option in lieu of the Company's proposed DDSM mechanism is "weather hedging." Please provide all information relied upon by Mr. Bettmann to make this claim, provide any information in his possession concerning the cost a utility would incur to purchase a weather hedge of the type envisioned in his testimony, and any examples of the use of weather hedging by utilities.

32. At pages 9 and 10 of his direct testimony, Mr. Bettmann discusses a proposal submitted by Minnegasco for a weather normalization adjustment (WNA) clause. Please provide all information in Staff's possession that pertains to the "public input hearing" and "feedback" received by the Commission from Minnegasco's bill insert, in which it attempted to explain the WNA. In addition, please provide all information pertaining to Minnegasco's request that its application for the approval of the WNA tariff be withdrawn.

33. At page 2 of his testimony, Mr. Bettmann states that a 65 degree day basis is "generally accepted as the temperature level where a building requires heating if the outside temperature drops below that point". Please provide copies of all studies relied upon that show that a 65 degree day basis is more reflective of use than a 60 degree day base.

Robert Towers

34. Please provide copies of all documents, workpapers and electronic files used or relied upon in preparing Mr. Tower's direct testimony and exhibits.

MONTANA-DAKOTA UTILITIES CO.
DATA REQUESTS TO THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF
DATED APRIL 29, 2003
DOCKET NO. NG02-011

35. At page 5 Mr. Towers discusses his contention that the Company's cost support for its Basic Service Charges is "greatly overstated" because it includes costs that are "not directly related to the service rendered to individual customers." Specifically, Mr. Towers states that "other non-assignable, overhead-type costs" that are treated by MDU as customer-related costs represent activities that are "required by the totality of all system functions." On that basis, would Mr. Towers agree that a portion of those overhead-type costs is required to support the distribution mains function? If his response is no, please provide a complete explanation for his response. In addition, please identify all specific cost accounts "not directly related to the service rendered to individual customers."

36. At page 5, Mr. Towers contends that if direct customer-related costs are recovered through non-gas commodity charges, thus "putting such costs at risk," that it provides the Company with "a cost control incentive." Please fully define the source and type of risk to which these costs would be subject and explain the basis for his statement that this risk would provide a cost control incentive not otherwise present. Provide examples of how he envisions this cost control technique would be implemented.

37. Does Mr. Towers prefer using performance-based ratemaking instead of cost of service ratemaking for purposes of setting a utility's rates? Please fully explain the basis for his response and provide case references for any proceeding where he has supported the use of performance-based ratemaking concepts.

38. In conducting an embedded class cost of service study, does Mr. Tower contend that costs should be evaluated and allocated to cost functions and classes of service on an incremental basis? If his response is yes, please provide a complete explanation of the basis for his response.

39. At page 21 of his direct testimony, Mr. Towers contends that there are certain costs that do not change as the Company's number of customers change. Among these costs, he contends that "administrative costs and various overhead-type costs" do not vary with changes in the number of customers. Please specify each type of administrative and overhead cost that Mr. Tower believes does not vary with the number of customers, and provide all quantitative and qualitative support for his belief.

40. For each type of administrative and overhead cost identified in Mr. Towers' response to Data Request No. 39 above, please indicate the allocation basis and related allocation factor(s) included in his class cost of service study that were used to assign each cost to the Company's various classes of service.

MONTANA-DAKOTA UTILITIES CO.
DATA REQUESTS TO THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF
DATED APRIL 29, 2003
DOCKET NO. NG02-011

41. At page 22 of his direct testimony, Mr. Towers states his belief that customer-related costs need not be recovered in a monthly service charge and that, "(o)bviously, assigning a portion of these costs to the commodity rate would still allow them to be recovered by the Company." Please provide all documents or studies in Mr. Towers' possession to support his contention that the Company in fact fully recovers these costs.

42. If Mr. Towers believes that no portion of the Company's administrative and overhead costs should be assigned to the customer cost function, would he agree that assigning these costs exclusively to the Company's demand and non-gas commodity related cost levels would result in an overstatement of those costs? If his response is no, please provide a complete explanation for his response.

43. Please reconcile the difference in Mr. Towers' definition at page 22 of customer costs as "costs directly related to maintaining customer service" with his earlier characterization of customer costs on page 5 where he rejects certain costs as "independent of incremental changes in the customer population."

44. Please provide a listing and definition of all of the "gas customer's service objectives" to which Mr. Towers refers on page 16 of his testimony.

45. Please describe the distinction between Mr. Towers' view that, from a customer's perspective, distribution mains are a "source of gas supply" and not "a facility that exists merely for access" to that same gas supply.

46. For each proceeding of the 200 proceedings cited on Appendix, page 3 please provide a full copy of any testimony where Mr. Towers proposed an adjustment to the allowance for federal and state income taxes which involved a consolidated tax savings adjustment or other adjustment similar to that which you have proposed in this case and the resulting orders.

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 CONTINUING HEARING** **NG02-011**

On December 30, 2002, 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 $2,173,380 or approximately 5.8%. On January 16, 2003, the Commission suspended the proposed schedule of rates for 90 days beyond January 30, 2003. On April 1, 2003, Commission Staff recommended that the suspension of the tariff be further extended for 60 days.

At its April 1, 2003, meeting, the Commission considered this matter. MDU concurred with Staff's recommendation. The Commission voted unanimously to grant the extension sought by Commission Staff.

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.

By order dated March 20, 2003, a hearing was scheduled for May 7 and 8, 2003, beginning at 9:00 A.M., on May 7, 2003, in Room 412 of the State Capitol Building, 500 E. Capitol, Pierre, South Dakota. On April 30, 2003, the Commission received MDU's motion to continue and reschedule the hearing.

At its May 6, 2003, meeting, the Commission considered this matter. MDU agreed to suspend implementing the proposed rate increase for 30 days after the June 29, 2003, expiration date. The Commission voted unanimously to grant the continuance. It is therefore

ORDERED, that the hearing scheduled for May 7 and 8, 2003, is continued and a new hearing shall be rescheduled at a later time.

Dated at Pierre, South Dakota, this 16th day of May, 2003.

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: 5/19/03

(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

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May 22, 2003

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

HAND DELIVERED

Pam Bonrud, Executive Secretary
Public Utilities Commission
500 East Capitol Avenue
Pierre, South Dakota 57501

RE: **IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE**
Docket: NG02-011
Our file: 4165

Dear Pam:

Enclosed are original and ten copies of MDU's motion to extend an informal deadline established between the parties for filing of MDU's rebuttal testimony. Please file the enclosure.

With a copy of this letter, I am forwarding a copy of the enclosure to the service list, this being intended as service by mailing.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

DAVID A. GERDES
DAG:mw
Enclosures
cc/enc: Karen Cremer
Dave Jacobson
Don Ball
Rita Mulkern

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MAY 2 2 2003

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 RATES FOR NATURAL GAS SERVICE	))))	NG02-011

MDU'S MOTION TO EXTEND DEADLINE FOR REBUTTAL TESTIMONY

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) moves that the informal deadline set for MDU's rebuttal testimony of May 23, 2003, be extended to a date to be agreed upon between the parties to the docket.

This motion is based upon the proposition that MDU just received staff's responses to the bulk of MDU's pending discovery on Wednesday, May 21. The materials are voluminous, constituting several hundred pages and the time necessary to incorporate that material into MDU's rebuttal testimony will extend beyond May 23. Because of the Memorial Day weekend and the planned absence of staff attorney Karen Cremer, it is impossible for the parties to agree upon an extended date prior to May 23.

WHEREFORE MDU prays that the Commission grant this motion and extend the date for service of MDU's rebuttal testimony.

Dated this 22nd day of May, 2003.

MAY, ADAM, GERDES & THOMPSON LLP

BY: _____

DAVID A. GERDES
Attorneys for MDU
503 South Pierre Street
P.O. Box 160
Pierre, South Dakota 57501-0160
Telephone: (605)224-8803
Telefax: (605)224-6289

CERTIFICATE OF SERVICE

David A. Gerdes of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 22nd day of May, 2003, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, to-wit:

Karen Cremer
Staff Attorney
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, SD 57501-5070

Dave Jacobson
Staff Analyst
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, SD 57501-5070

David A. 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	**))))**	**ORDER FOR AND NOTICE OF HEARING NG02-011**

On December 30, 2002, 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 $2,173,380 or approximately 5.8%.

At its regularly scheduled meeting of January 16, 2003, 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 February 7, 2003. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by MDU for 90 days beyond January 30, 2003. 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. A hearing was scheduled for May 7 and 8, 2003. On April 30, 2003, the Commission received MDU's motion to continue and reschedule the hearing. At its May 6, 2003, meeting, the Commission granted MDU's motion to continue and reschedule the hearing.

A hearing shall be held beginning at 8:00 a.m., on June 24, 2003, in Room 412, continuing at 1:00 p.m., on June 25, 2003, in Room 413, and continuing at 8:00 a.m. on June 26, 2003, 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 $2,173,380.

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 hearing shall commence at 8:00 a.m., on June 24, 2003, in Room 412, continuing at 1:00 p.m., on June 25, 2003, in Room 413, and continuing at 8:00 a.m. on June 26, 2003, in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota.

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 5th day of June, 2003.

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: 6/5/03

(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

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

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MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG02-011
REBUTTAL TESTIMONY

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.

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

June 6, 2003

Ms. Pam Bonrud
Executive Director
South Dakota Public Utilities Commission
State Capitol Building
500 East Capitol
Pierre, SD 57501-5070

Re: General Natural Gas Rate Application
Docket No. NG02-011

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. herewith submits the original and ten (10) copies of the rebuttal testimony of Dr. J. Stephen Gaske, Mr. Don M. Hamann, Ms. Rita A. Mulkern, Mr. Richard A. Espeland, Mr. Alvin J. Feist, Mr. Russell A. Feingold and Ms. Tamie A. Aberle.

Copies of the rebuttal testimony have been mailed to Basil L. Copeland Jr. and Robert G. Towers.

Please acknowledge receipt by stamping or initiating 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
Director of Regulatory Affairs

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

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

BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. NG02-011

PREPARED REBUTTAL TESTIMONY OF

J. STEPHEN GASKE

Q1. Are you the same J. Stephen Gaske whose Prepared Direct Testimony was filed earlier in this proceeding?

A. Yes.

Q2. What is the purpose of this Prepared Rebuttal Testimony?

A. Montana-Dakota Utilities Co. ("Montana-Dakota") has asked me to review and comment upon the Testimony filed by Basil L. Copeland on behalf of the Staff of the Public Utilities Commission of South Dakota ("Staff"). After review of this testimony I conclude that the allowed rate of return proposed by the Staff is below the cost of capital for Montana-Dakota's South Dakota natural gas distribution operations and would be insufficient to attract capital on reasonable terms.

Q3. Would you please summarize your Prepared Rebuttal Testimony?

A. There is one overarching flaw that permeates Mr. Copeland's entire testimony and ultimately renders his analyses and recommendation nearly useless for setting the allowed rate of return for Montana-Dakota's South Dakota natural gas distribution operations. This flaw is his belief that this Commission does not need to set an allowed rate of return that will attract capital for construction and

maintenance of natural gas distribution assets required to provide service to South Dakota customers. Instead, he contends that this Commission should set an allowed return that is:

> "... fair to MDU's shareholders, and ***not necessarily to a particular segment of the business***."[1]

Indeed, as my rebuttal testimony shows, this overarching contention leads Mr. Copeland to adopt analytical methods that do not, and are not intended to, provide a rate of return that will attract capital for investment in Montana-Dakota's South Dakota natural gas distribution operations.

Mr. Copeland also makes several fundamental errors in calculating a required rate of return that cause him to understate and incorrectly estimate the cost of capital for the proxy companies that he uses in his analysis.

His first error comes in his selection of comparable companies since he has excluded from his group of proxy companies most of the large, well-recognized, publicly-traded natural gas distribution companies and instead primarily used companies that have no more than a minor portion of their revenues and assets associated with gas distribution operations. Because his study is based on proxy companies that are not primarily gas distribution companies, Mr. Copeland's analysis has little or no relevance for setting a rate of return for Montana-Dakota's gas distribution operations in this proceeding.

[1] Testimony of Basil L. Copeland, SDPUC Docket No. NG02-011, page 8, lines 5-8, underscore in the original, bold italics added.

1 Next, he fails to provide an accurate estimate of the long-term growth rate
2 that investors expect from the proxy companies because he places excess
3 emphasis on Value Line short-term growth forecasts and does not recognize the
4 nature and significance of earnings growth in the dividend discount model.

5 Moreover, Mr. Copeland erred by not making a flotation cost adjustment
6 to his DCF results in order to account for the fact that he is using investor return
7 requirements in the secondary market for common stocks in order to estimate the
8 cost of capital that Montana-Dakota requires in order to raise common equity
9 funds in the primary market on reasonable terms. A correct calculation of the cost
10 of capital requires a proper recognition of the difference between stock prices in
11 secondary markets and the net proceeds that would be realized if a utility were to
12 attempt to raise funds by issuing new common stock in the primary markets.

13 Mr. Copeland's Capital Asset Pricing Model ("CAPM") analysis has no
14 value for estimating the cost of capital since the CAPM model does not correctly
15 measure and price risk and no longer can be considered to be a valid approach for
16 estimating the cost of capital. In addition, in Mr. Copeland's testimony
17 incorrectly measures the market premia required because he incorrectly relies
18 upon geometric mean data for the market risk premium in circumstances that
19 require use of an arithmetic mean.

20 Finally, I will explain the errors that result from Mr. Copeland's
21 misunderstanding of the role played by corporations as investment agents for
22 shareholders.

Q4. How did Mr. Copeland calculate his recommended rate of return for this proceeding?

A. As a proxy, he used a group of companies that he claims are "... comparable to MDU as a whole."[2] However, instead of using companies that are comparable to MDU as a whole, he used a group of "... 20 electric utilities with gas distribution operations."[3] Next, Mr. Copeland conducted his two variations of a DCF analysis on his electric utility group. He also performed a supplemental CAPM analysis on the electric utility group. In his two DCF analyses, the average and median rates of return sample group were between 9.83 and 9.88 percent. Based on these results, he recommended an allowed rate of return of 9.75 percent for Montana-Dakota's South Dakota gas distribution operations. In other words, he is recommending a return that is below the average indicated for his electric utility group.

Non-Comparable Sample Group

Q5. Have you compared the level of gas distribution operations conducted by the Moody's Natural Gas Distribution group, which you used in your analysis, with the level of such operations conducted by Mr. Copeland's sample group?

A. Yes. Exhibit No. ___(JSG-4) contains this comparison. All of the companies in the Moody's Gas Distribution group have a greater proportion of assets invested in gas distribution facilities than any of the companies in Mr. Copeland's sample group. Similarly, with one exception, all of the Moody's Gas

[2] Id., page 8, lines 12-13.
[3] Id., page 8, lines 15-16.

1 Distribution companies derive a greater share of revenues than the companies in
2 Mr. Copeland's sample group.

3 Of even greater significance is the enormous disparity between the two
4 groups. The Moody's Gas Distribution companies have a median of **89 percent**
5 of their assets engaged in gas distribution operations, while Mr. Copeland's
6 companies have a median of only **16 percent** of assets engaged in natural gas
7 distribution operations. Similarly, the median portion of revenues derived from
8 gas distribution operations is **75 percent** for the Moody's Gas Distribution
9 companies and only **22 percent** for Mr. Copeland's group.

10 All of the Moody's Gas Distribution companies have more than 50 percent
11 of their assets and revenues associated with gas distribution operations. In most
12 instances the gas distribution proportions for the Moody's companies exceed 70
13 or 80 percent. In contrast, there are only four instances in which Mr. Copeland's
14 companies have as much as 50 percent of their assets or revenues associated with
15 gas distribution operations. Sempra (54%), NISource (51%) and Vectren (50%)
16 derive barely more than 50 percent of their revenues from gas distribution
17 operations while only Vectren (54%) has as much as 50 percent of its assets
18 associated with gas distribution. In nearly all other instances, Mr. Copeland's
19 companies have less than 30 percent of their assets and revenues associated with
20 gas distribution operations.

21 Clearly, the Moody's Gas Distribution companies provide a far superior
22 proxy group for estimating the rate of return required for Montana-Dakota's
23 natural gas distribution operations. On the other hand, Mr. Copeland's sample

group of companies generally have such a small proportion of their business involved with gas distribution operations that his study cannot tell us much, if anything, about the allowed rate of return that the Commission should adopt in this proceeding.

Q6. Why did you indicate earlier that Mr. Copeland incorrectly claims to be using companies that are "... comparable to MDU as a whole?"

A. Mr. Copeland argues that the correct comparable group of companies is a group that is similar to MDU Resources Group ("MDU") as a whole since a share of MDU stock carries an undivided ownership interest in all of MDU's segments and operations. Ignoring for the moment Mr. Copeland's misunderstanding of the investor and investment process that is relevant for this proceeding, his analysis is problematic because neither the parts, nor the sum of the parts, in his sample group bears much resemblance to MDU. MDU's business and operating segments are as follows:

	Assets	%	Revenues	%
Electric Utility	$310,519	11	$162,616	8
Natural Gas Distribution	170,672	6	186,569	9
(Third-Party) Utility Services	230,888	8	458,660	23
Pipeline and Energy Services	302,972	11	110,224	5
Natural Gas and Oil Production	554,420	19	148,158	7
Construction Materials and Mining	1,137,697	40	962,312	47
Independent Power Production	148,770	5	2,998	0

Although each of Mr. Copeland's sample companies is an electric company with some gas distribution operations, none of his companies are heavily involved in competitive, cyclical businesses such as construction

1 materials and mining. But that is MDU's largest business. Nor do Mr.
2 Copeland's sample companies have nearly the same level of involvement as
3 MDU in gas pipeline and oil and gas production. Proportionately, MDU electric
4 utility operations are similar in size to its utility services unit which acts as a
5 general contractor providing construction or maintenance services to other
6 utilities around the country and manufactures certain types of construction
7 equipment.

8 There is no evidence that Mr. Copeland has attempted to compile a sample
9 group that includes companies involved in construction materials, mining, oil and
10 gas production, contract services and independent power production. Thus,
11 despite the claim that he is using a sample group of companies that is "...
12 comparable to MDU as a whole ...," it is clear that Mr. Copeland's sample group
13 is neither comparable to MDU as a whole nor is it comparable to MDU's natural
14 gas distribution operations.

15 **Q7. Do you agree that the appropriate sample group for this proceeding must**
16 **contain companies that are similar to MDU Resources Group?**

17 A. No, this proceeding involves the just and reasonable rates and allowed rate
18 of return for gas distribution operations, therefore, the appropriate sample group is
19 companies that are primarily involved in gas distribution operations.

20 If the Commission determines that it must set a return that is appropriate
21 for natural gas distribution operations in this proceeding, Mr. Copeland's electric
22 utility sample group should be rejected because it is not representative of, and is
23 not meant to be representative of, natural gas distribution company operations.

1 Instead, the Moody's Natural Gas distribution company group provides the
2 appropriate proxy group to use in this proceeding.

3 On the other hand, if the Commission agrees with Mr. Copeland's
4 assertion that the task at hand is to determine a rate of return for MDU's
5 operations as a whole, including all business segments, one must use a sample
6 group that includes companies with significant operations in construction
7 materials, mining, contract services, oil and gas exploration and development,
8 natural gas transmission and independent power production. Obviously, Mr.
9 Copeland has not provided a sample group that is intended to be representative of
10 these segments of MDU's operations. Instead, he has selectively ignored his own
11 stated objective and chosen to use only companies that are primarily electric
12 utilities with some gas distribution operations. As a result, without an additional
13 inquiry into the level of returns that investors require to invest in businesses such
14 as construction materials, mining, contracting, oil and gas production, etc., the
15 Commission does not have evidence necessary to render a decision that fulfills
16 Mr. Copeland's stated goal of setting a rate of return for MDU's operations as a
17 whole.

18 **Significance of Earnings Growth**

19 **Q8. At pages 16-17 of his testimony Mr. Copeland criticizes your use of a**
20 **combination of analysts' long-term earnings growth forecasts and the projected**
21 **Value Line retention growth rate forecasts. Is his criticism valid?**

22 A. No. Mr. Copeland is under the mistaken impression that expected
23 earnings growth, including expected growth due to retention and reinvestment of

earnings, is unrelated to expected future dividend growth. This mistake leads him to suggest at page 17, lines 1-5 that investors' expected growth rates in earnings are a fatally flawed measure of expected dividend growth. However, as every analyst knows, a company with good investment opportunities will often prefer to retain and reinvest its earnings rather than increase the dividend payout. So long as the retained earnings can be reinvested to earn at least the cost of capital, investors often are willing to forego near-term dividend increases and trade lower near-term growth in dividends for higher long-run growth in dividends. However, even in the relatively near term, the earnings growth rate is the best indicator of the expected long-term growth expected for dividends.

The DCF model effectively requires an estimate of the implicit average long-run growth rate in dividends. However, in the long run it is earnings growth that is most important for investor expectations because at any given point in time the long-run dividend growth rate should approximately match the expected earnings growth rate. The near-term growth rates of earnings and dividends need not be equal for the expected long-term growth rates to be equal -- so long as the company continues to earn the cost of capital on earnings retained in the company, investors can expect that the time-weighted, long-run average growth rate in future dividends will reasonably approximate the expected long-term growth rate in earnings.

Q9. At page 17, lines 6-8 Mr. Copeland states that "(w)hile 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." Is he correct in this reasoning?

A. No. He is correct that dividends are paid out of earnings – that is the reason investors focus closely on long-term earnings forecasts and not necessarily on long-term dividend forecasts in evaluating common stock values. However, Mr. Copeland first errs by ignoring at this point in his testimony the ability of companies to trade off lower near-term dividend growth for even higher long-term dividend growth, as described in the preceding answer. This trade-off often produces near-term earnings growth estimates that are higher than the near-term dividend growth estimates, but it does not necessarily mean that expected long-term dividend growth is equal to near-term dividend growth forecasts.

His second error comes when he implicitly contradicts himself by observing that the consensuses of analysts' long-term earnings growth forecasts exceed Value Line's near-term dividend growth forecasts, and then concludes that:

> "This disparity reflects a projected near-term <u>decline</u> in dividend payout, resulting in a rise in the earnings retention rate."[4]

In fact, all of Mr. Copeland's arguments for why he places heavy emphasis on near-term dividend and book value growth appear to be based on the belief that all growth must come from retained earnings. However, earnings growth also can be achieved from a financial perspective by selling new common stock at a price greater than book value (the "sv" growth component that Mr. Copeland has used in the past), paying down debt to reduce interest expenses, by borrowing to invest

[4] Id., page 9, lines 14-16, emphasis added.

in projects that have a return that exceeds the cost of debt, or by "monetizing" a portion of expected growth by selling at a multiple of book value lines of business that have high future growth and earnings potential. Some or all of these approaches are often pursued by companies to achieve growth. Mr. Copeland's reason for concluding that "current market conditions" preclude the use of earnings growth forecasts as a proxy for dividend growth is undermined by the fact that companies often use various combinations of these means to grow more rapidly than the earnings retention rate would allow. Thus, earnings can grow more rapidly than dividends in the near-term without sacrificing future growth prospects. Analysts' forecasts generally include assessments of all of the methods of growth available to a company – not just the earnings retention growth. Consequently, these forecasts provide a better indicator of long-term dividend growth expectations than either a simple retention growth rate assumption or a near-term forecast of dividend growth. so that earnings, dividends and book value must proceed are mathematically linked so that other these factors must be

Q10. How can a company grow by issuing common stock?

A. A company that is able to issue stock at a price that exceeds book value and invest the proceeds in new projects that generate returns and values similar to its existing projects can maintain a continual growth rate in the earnings and dividends of its existing investors even if it does not increase its rate of return or reinvest any of its earnings. For example, a company that sustains a market-to-book ratio of 2.0 and issues new shares of stock to steadily increase the number of shares outstanding by 10 percent each year. As long as the proceeds from the new

shares are invested in projects that maintain the market-to-book ratio at a level of 2.0, the company in this example can achieve a growth rate in its book value per share of 9.09 percent per year without retaining any earnings or otherwise sacrificing its dividend payout.

Q11. How is it possible for a company to grow by borrowing?

A. If a company can borrow to fund new projects that provide a return that exceeds the interest rate paid for the loan, the company can achieve growth in its earnings and dividends without either retaining earnings or issuing new common stock. For example, a company might borrow to invest in a project that earns an overall return of 15.5 percent. If the cost of debt is only 8 percent and the project also generates enough cash to repay the debt, the company can increase its earnings and dividends by undertaking this project. This growth can be accomplished without retaining earnings or issuing new common stock. Once the project has generated sufficient cash flow to repay the debt undertaken to finance the project, all of the available return will go to the owners.

Q12. How is it possible for a company to "monetize" expected future growth by selling assets at a multiple of the current book value or earnings?

A. Very often a company's stock will trade at a rate above book value or at a high multiple of current earnings because investors expect earnings that exceed the cost of capital or substantial growth in the future from some or all of the company's current operations. Although these high earnings and growth expectations might be impounded in the stock price, thereby producing a lower dividend yield, the growth will not necessarily be realized for many years in the

1 future. However, the company may have opportunities to realize substantial
2 growth in the near future merely by selling some of the assets that are expected to
3 achieve high earnings and growth. For example, in 1995 The Williams
4 Companies experienced 85.0 percent growth in its book value per share by selling
5 a portion of its rapidly growing telecommunications operations. Thus, through
6 the sale of certain assets, Williams was able to accelerate the realization of some
7 of its expected growth without the need to invest in the future or retain earnings in
8 order to fund that growth.

9 **Q13. What is the appropriate method for estimating the long-term dividend growth**
10 **expectations of investors?**

11 A. The appropriate method depends in large part on the expected strategies
12 and methods of operating that a specific company utilizes. However, any
13 reasonable method must consider analysts' long-term earnings growth forecasts,
14 combined with long-term retention growth forecasts, and recognition that
15 retention growth is just one of the many ways that companies can achieve growth
16 over time.

17 **Purpose and Need for a Flotation Cost Allowance**

18 **Q14. Does the investor return requirement that is estimated by a DCF analysis**
19 **need to be adjusted for flotation costs in order to estimate the cost of capital?**

20 A. Yes. There are significant costs associated with issuing new common
21 equity capital and these costs must be considered in determining the cost of
22 capital. Anyone who has ever taken out a mortgage to buy a house is aware that
23 the "effective" interest rate is higher than the "stated" interest rate because the

1 homebuyer pays loan origination fees, points and closing costs in connection with
2 raising the capital to buy a house. This same concept applies to public utility
3 companies: the "effective" cost of capital is higher than the "stated" cost of
4 capital because there are flotation costs associated with raising new common
5 equity capital.

6 The need for a flotation cost adjustment is especially acute when the cost
7 of common equity is estimated by conducting a DCF analysis that is based on the
8 prices of common stocks traded in the "secondary" markets on stock exchanges.
9 Because the purpose of the allowed rate of return in a regulatory proceeding is to
10 estimate the cost of capital that the regulated company would incur to raise money
11 in the "primary" markets, a DCF estimate of the returns required by investors in
12 the "secondary" markets must be adjusted for flotation costs in order to provide
13 an estimate of the cost-of-capital that the regulated company requires in order to
14 raise capital on reasonable terms in the "primary" markets.

15 **Q15. Would you please describe the difference between "primary" and "secondary"**
16 **markets for common equity?**

17 A. When a company issues new common equity in order to raise cash for
18 investment in plant, or to otherwise run its operations, it does so in the "primary"
19 market. The "primary" market is defined very simply as the market in which the
20 stock is first sold in order to raise cash funds to be used by the issuer. In this
21 "primary" market, the company generally hires an investment banker, or a
22 syndicate of bankers and brokers, to float its stock issue to the public. In
23 connection with raising cash funds through a "primary" market sale of common

1 stock a company incurs significant costs of preparing and filing documents with
2 the Securities and Exchange Commission ("SEC"), as well as other regulatory
3 agencies, and issuing prospectuses. In addition, in the "primary" market the
4 issuing company generally must pay a significant percentage of the proceeds from
5 the stock issuance to the investment banker, or the syndicate of bankers and
6 brokers, who undertakes to find investors who will provide cash to the issuing
7 company.

8 Once stock has been issued to investors in the "primary market," those
9 investors who initially provided cash to the issuing company may re-sell or
10 "trade" the stock with other investors in the "secondary" market. Much of the
11 trading in the "secondary" market occurs on stock exchanges and buyers and
12 sellers are not required to file prospectuses with the SEC. The crucial difference
13 between stock issued in the "primary" market and stock traded in the "secondary"
14 market is that the issuing company does not receive any additional funds when its
15 stock trades in the "secondary" market. Instead, the ownership of the stock
16 merely changes hands between various investors. In addition, the brokerage fees
17 associated with buying and selling stock in the "secondary" market generally are
18 incurred by both the buyer and the seller, and are a small fraction of the level of
19 the flotation costs incurred by a company that attempts to raise cash by issuing
20 stock in the "primary" market.

1 **Q16. Have you quantified the cost of raising capital by issuing stock in the**
2 **"primary" market?**
3 A. Yes. Schedule 3 of Exhibit No. ___(JSG-2) shows a representative
4 sample of flotation costs incurred by natural gas distribution and transmission
5 companies have averaged 4.85 percent in the past. When a DCF analysis based on
6 stock prices and dividend yields in the "secondary" market is used to estimate the
7 required rate of return, a flotation cost adjustment is essential in order to account
8 for the difference between (i) stocks traded between investors in the secondary
9 markets and (ii) stock issued in the primary market to raise capital for plant
10 construction and utility operations.

11 **Q17. In your opinion, is a flotation cost adjustment required to meet the tests**
12 **established for a reasonable rate of return?**
13
14 A. Yes. The Supreme Court established the "Capital Attraction" standard as
15 one test of a reasonable allowed rate of return. For example, in *Bluefield Water*
16 *Works & Improvement Company v. Public Service Commission of West Virginia*
17 (262 U.S. 679, 693 (1923)), the Court indicated that:

18 *"The return should be reasonably sufficient to assure confidence*
19 *in the financial soundness of the utility and should be adequate,*
20 *under efficient and economical management, to maintain and*
21 *support its credit and* ***enable*** *it to raise the money necessary for*
22 *the proper discharge of its public duties."*[5]

23 Similarly, in *Federal Power Commission v. Hope Natural Gas Company (320 U.S.*
24 *591, 603 (1944))* the Court described the relevant criteria as follows:

[5] Emphasis added.

> "*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.... 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.*"[6]

The Court's requirement that the allowed return must "enable" a company to raise capital does not mean that the company must raise capital within some specified time period. Instead, it means that the company must have in place the ability to attract capital so that it can exercise that ability if and when required. By its use of the word "moreover" the Court made it clear that an allowed return is not sufficient if it merely allows the company to meet its current financial obligations. Instead, an additional and overriding requirement is that the return also must be sufficient to assure that the company can attract capital and maintain its financial integrity. In effect, the "yardstick" established by the Court poses a hypothetical stock issue as a means for measuring the reasonableness of the allowed rate of return: *if* the allowed rate of return is sufficient to allow the company to raise new capital on reasonable terms, *then* the rate of return is legally adequate.

Because a rate of return established from information in the "secondary" market indicates only the level of return investors require when they trade common stock among themselves, that return estimate excludes the additional flotation costs that must be paid in order to enable the utility to attract capital in the "primary" market. Thus, an allowance for flotation costs is required in order to meet the "Capital Attraction" standard.

[6] Emphasis added.

Q18. Is the need for a flotation cost adjustment to the rate of return widely recognized among economists as a required part of an allowed rate of return that will attract capital without diluting the value of existing investors' equity?

A. Yes. In commenting on the fair rate of return in his classic treatise on public utility ratemaking, Bonbright stated that:

> "...book values (with allowances for the probable need to underprice new common-stock offering) should set a floor to the market values..."

James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 249. Similarly, Myron Gordon, the man who is credited with having developed the DCF model for estimating rate of return, has stated that a regulatory agency should set the allowed rate of return greater than the investor return requirement so as to allow the firm to issue stock at a price that will yield net proceeds equal to book value. Professor Gordon advocates the following adjustment:

> *"The agency need only estimate the proportion that the proceeds per share on an issue bear to the price of the stock and adjust the allowed rate of return so that the price per share is the indicated ratio of the book value per share. If the proceeds on an issue are 91 percent of market price, the agency should maintain market price at about 110 percent of book value."*

Myron J. Gordon, *The Cost of Capital to a Public Utility*, Michigan State University, 1974, pages 165-166. In order to meet this requirement, the flotation cost adjustment must be applied to the entire rate of return. The flotation cost adjustment that I have proposed attempts to meet the same standards advocated by these other economists.

Q19. Did Mr. Copeland neglect to include a flotation cost adjustment in calculating his estimates of the cost of capital?

A. Yes. Consequently, at the very least his "secondary" market rate of return estimates must be multiplied times the flotation cost adjustment factor, 1.0475, in order to estimate the rate of return that Montana-Dakota requires in order to attract capital in the "primary" market on reasonable terms.

Irrelevance of Mr. Copeland's CAPM Analysis

Q20. Is Mr. Copeland's Capital Asset Pricing Model ("CAPM") analysis useful in determining a required rate of return?

A. No. Although the Capital Asset Pricing Model ("CAPM") approach generally has received some acceptance in the past, there is extensive research that indicates severe practical and theoretical problems with applying the CAPM. In addition, recent empirical research suggests that the CAPM, as it usually is applied, may have no validity whatsoever. For example, more than a decade ago Value Line made the following observation:

> "'The fact is that Beta, as the sole variable explaining returns on stocks, is dead.' These findings support previous studies that have called into question the real-world applicability of the CAPM Beta, including papers by Keim (Financial Analysts Journal, 1986), and Roll (Journal of Financial Economics, 1977). Never before, however, has the lack of a statistically significant relationship between beta and return been so rigorously and dramatically established. (Value Line Industry Review, March 13, 1992, p. 1-8)"

Thus, although Mr. Copeland states at page 15, lines 12-14 of his testimony that his CAPM analysis is based on Beta estimates calculated by Value Line, it is clear that Value Line no longer believes that it is legitimate to use its Beta estimates to

calculate the cost of capital. Consequently, Mr. Copeland's CAPM analysis has no significance for estimating the required rate of return.

Benchmark Analyses

Q21. At page 17, lines 15-18 of his testimony, Mr. Copeland criticizes you for relying on the arithmetic mean for analyzing the level of return that should be allowed in this proceeding. Is Mr. Copeland's criticism on point?

A. No. I believe Mr. Copeland is fundamentally mistaken in his position because he fails to distinguish between (i) measuring historical and/or projected average returns achieved, and (ii) establishing an allowed rate of return. For any data series that has rates of return that fluctuate from year to year, the geometric mean rate of return will be less than the arithmetic mean growth rate. When one wants to measure the overall average return earned over a period of past years, it is usually the geometric mean growth rate that one would calculate. Similarly, if one wanted to project an ending value for an investment over a period of years, one would also use a geometric average growth rate for this purpose. Mr. Copeland appears to have this concept correct.

However, he goes astray by thinking these facts also mean that an allowed rate of return should be established or evaluated using a geometric mean rate of return to calculate risk premiums. If the object is to set an allowed rate of return that will give a company a reasonable opportunity to achieve a specific geometric average rate of return, the generally higher arithmetic average rate of return must be allowed. As returns fluctuate, the geometric average return will be less than the arithmetic return.

To illustrate this point, I have prepared Exhibit No.___(JSG-5) that compares the results that would occur if the allowed rate of return was re-set every three years to correspond to the historic average rate of return during the prior three years. Page 1 of this exhibit shows that an allowed rate of return that is initially based on the historic *arithmetic* average rate of return, 15 percent, will produce a *geometric* average rate of return of 14.71 percent after three years. If the rate of return in the fourth year is set to 15 percent, the *arithmetic* average rate of return during years 1-3, the company again will earn a *geometric* average rate of return of 14.71 percent. In this example, the pattern would continue for 30 years and the company would achieve the a *geometric* average rate of return of 14.71 percent over the 30-year period. Note, however, that in order to achieve the historic geometric average rate of return of 14.71 percent, the regulator needed to repeatedly set the allowed rate of return equal to 15.00 percent, which is the *arithmetic* average rate of return.

Q22. What would happen if the regulator took Mr. Copeland's advice and used the geometric average rate of return as the standard for allowed rates of return?

A. That result is demonstrated on page 2 of Exhibit No.___(JSG-5). As in the preceding example, the regulator initially observes that historically the *arithmetic* average rate of return has been 15.00 percent and the *geometric* average rate of return has been 14.71 percent. However, this time the regulator takes Mr. Copeland's advice and uses the *geometric* average rate of return to set the allowed rate of return equal to 14.71 percent. After three years the company achieves an *arithmetic* average rate of return 14.71 percent and a *geometric*

average rate of return of only 14.42 percent. Seeing the obvious failure of the company to achieve the intended 14.71 percent *geometric* average rate of return during the first year, the regulator could again take Mr. Copeland's advice and base a new allowed rate of return for years 4-6, on the observed *geometric* average rate of return from the first three years: 14.42 percent. However, the geometric average rate of return achieved during years 4-6 would be only 14.12 percent. After repeated iterations of setting allowed rates of return based on *geometric* average data, the company would be realizing a *geometric* average rate of return of only 11.76 percent in years 28-30 – which is considerably less than the *geometric* average rate of return that the regulator intended.

Obviously this example is exaggerated and no regulator would actually set returns in the manner depicted. However, this example serves to illustrate that one must use *arithmetic* average returns and risk premiums in setting or evaluating an allowed rate of return.

Q23. At page 18, lines 3-7 of his testimony, Mr. Copeland claims that your Alternative Equity Investment analysis is irrelevant because he claims that investors do not have the opportunity to earn the same returns on book value that corporations are able to earn by investing in plant and equipment. Is he correct?

A. No. Mr. Copeland is confusing the "primary" market for investing in hard assets such as utility plant with the "secondary" market for investing in paper assets such as already-issued common stocks. Investors who own stock in a corporation have access to returns on book equity at all times. Managers of most

1 corporations continually consider what to do with the stockholders' cash that is
2 held by the corporation. Managers may pay cash dividends to shareholders, or
3 reinvest cash in a multitude of potential investments to create higher future
4 earnings. Expected earnings on the book value of potential investments are a
5 primary determinant of how corporations use and allocate the stockholders'
6 money. Thus, Mr. Copeland is incorrect. Stockholders, through managers acting
7 as their agents, do have access to book value investments.

8 **Q24. Does Mr. Copeland exhibit the same confusion between "primary" markets**
9 **and "secondary" markets for capital when he recommends that the**
10 **Commission should not set an allowed rate of return that is appropriate or**
11 **sufficient for the risks involved in Montana-Dakota's South Dakota gas**
12 **distribution operations?**

13 A. Yes. On page 8, lines 10-13 of his testimony makes the following
14 incorrect observation:

15 "Investors cannot invest in just the gas distribution operations of
16 MDU. They must invest in MDU as a whole."

17 However, when MDU's management considers what to do with stockholders'
18 money that is generated by earnings and depreciation, they could conceivably: (i)
19 pay the money out to the stockholders in the form of dividends; or (ii) they could
20 invest at book value in pipe and equipment to provide natural gas distribution
21 service in South Dakota; or (iii) it is even possible for them to invest at book
22 value in any number of possible unregulated facilities. Similarly, when
23 management raises capital through new common stock issues, these funds, which

1 belong to the stockholders, also could be invested at book value in unregulated
2 facilities and operations.

3 Thus, it is obvious that MDU's investors have the ability to achieve the
4 same returns on book value that are available to other companies in the economy.
5 In addition, it is clear that MDU's investors continually must decide whether to
6 "... invest in just the gas distribution operations of MDU" or to do something else
7 with their money. Mr. Copeland encounters his various problems with this
8 concept because he defines "investors" as the group of relatively passive MDU
9 stockholders that generally purchase shares that are traded in the secondary
10 market on a stock exchange. However, the decision to invest or not invest
11 stockholders' money in pipe and other gas distribution facilities is made by the
12 company management, acting as agent for the stockholders. When one realizes
13 that the corporation, acting in the collective interest of shareholders, is the
14 relevant decision-making "investor," it is easy to see why Mr. Copeland is wrong
15 in asserting that the Commission's task is to set a rate of return for MDU as a
16 whole, and not a rate of return for the regulated gas distribution segment of the
17 company. This realization that the relevant "investor" is the corporation, acting as
18 agent for the stockholders, also highlights the fallacy of Mr. Copeland's
19 contention that "investors" cannot invest at book value in plant and facilities.

20 **Q25. Does the average return on book value provide one type of "sanity check" on**
21 **the level of return required by investors?**

22 A. Yes. I have no doubt that investors in gas distribution utility assets similar
23 to Montana-Dakota's South Dakota operations do not require the 29.4 percent

return on average book value that investors in industrial companies have achieved in recent years. However, that is the average level of returns in recent years that Montana-Dakota must compete against in attracting capital.

An allowed rate of return established by the DCF method should make the value of the gas distribution operations equal to the book value of those operations in the absence of a flotation cost adjustment. In other words, the purpose of the DCF analysis is to find the rate of return that will make investors indifferent between investing to provide gas distribution service to the public or investing in, for example, U.S. Treasury bills. In contrast, when investors or corporations invest in non-regulated assets the market value of those investments has been many times the book value.

Consequently, when managers of a company evaluate possible investments they must consider the possibility of investing $1.00 in gas distribution utility assets with the expectation that the market value of those assets will be $1.00 and, thus, no value will be created for investors. On the other hand, when managers invest $1.00 in non-utility assets, they have a reasonable possibility of earning a 29 percent return on that investment and turning $1.00 of book value into $5.00 of market value.[7] Thus, while Montana-Dakota does not require anything close to a return of 29 percent on its gas distribution investments, knowledge of such potential average returns that Montana-Dakota must compete against helps place Montana-Dakota's required rate of return of 11.75 percent in perspective.

[7] The average market-to-book ratio for the S&P Industrial Index has been close to 5.00 in the past year.

Q26. Does this conclude your Prepared Direct Testimony?

A. Yes.

Montana-Dakota Utilities Co.

Percentage of Assets or Plant Associated With Natural Gas Distribution Operations For Moody's Gas Distn. Group and Mr. Copeland's Group

Rank	Company	% Gas Distribution Assets or Plant
1	**Northwest Natural Gas**	**97%**
2	**WGL**	**92%**
3	**Laclede**	**91%**
4	**Peoples Energy**	**87%**
5	**AGL**	**86%**
6	**KeySpan**	**59%**
7	Vectren	54%
8	NISOURCE	32%
9	Energy East	30%
10	Sempra	28%
11	Dominion Resources	22%
12	SCANA Corp.	21%
13	PS Enterprise Group	20%
14	Wisconsin Energy	18%
15	CH Energy Group	17%
16	PNM	17%
17	Consol. Edison	15%
18	WPS Resources	12%
19	DTE Energy	10%
20	NSTAR	10%
21	Northeast Utilities	9%
22	Cinergy Corp.	9%
23	Constellation Energy	8%
24	Exelon	5%
25	Ameren Corp.	4%
26	Entergy	1%
	Median Moody's Gas Distn. Co.	**89%**
	Median of Mr. Copeland's Group	**16%**

Note: **BOLD** indicates Moody's Natural Gas Distribution Companies used in Prepared Direct Testimony of J. Stephen Gaske.

Montana-Dakota Utilities Co.

Percentage of Revenues Associated With Natural Gas Distribution Operations For Moody's Gas Distn. Group and Mr. Copeland's Group

Rank	Company	% Gas Distribution Revenue
1	**Northwest Natural Gas**	**97%**
2	**AGL**	**97%**
3	**Laclede**	**78%**
4	**Peoples Energy**	**72%**
5	**WGL**	**59%**
6	Sempra	54%
7	**KeySpan**	**53%**
8	NISOURCE	51%
9	Vectren	50%
10	Cinergy Corp.	41%
11	Energy East	26%
12	PS Enterprise Group	26%
13	Dominion Resources	25%
14	Wisconsin Energy	25%
15	PNM	23%
16	SCANA Corp.	23%
17	DTE Energy	20%
18	CH Energy Group	15%
19	Consol. Edison	14%
20	Constellation Energy	12%
21	WPS Resources	12%
22	NSTAR	11%
23	Ameren Corp.	8%
24	Northeast Utilities	6%
25	Exelon	4%
26	Entergy	2%
	Median Moody's Gas Distn. Co.	**75%**
	Median of Mr. Copeland's Group	**22%**

Note: **BOLD** indicates Moody's Natural Gas Distribution Companies used in Prepared Direct Testimony of J. Stephen Gaske.

Montana-Dakota Utilities Co.

Percent of Assets Associated With Gas Distribution Operations

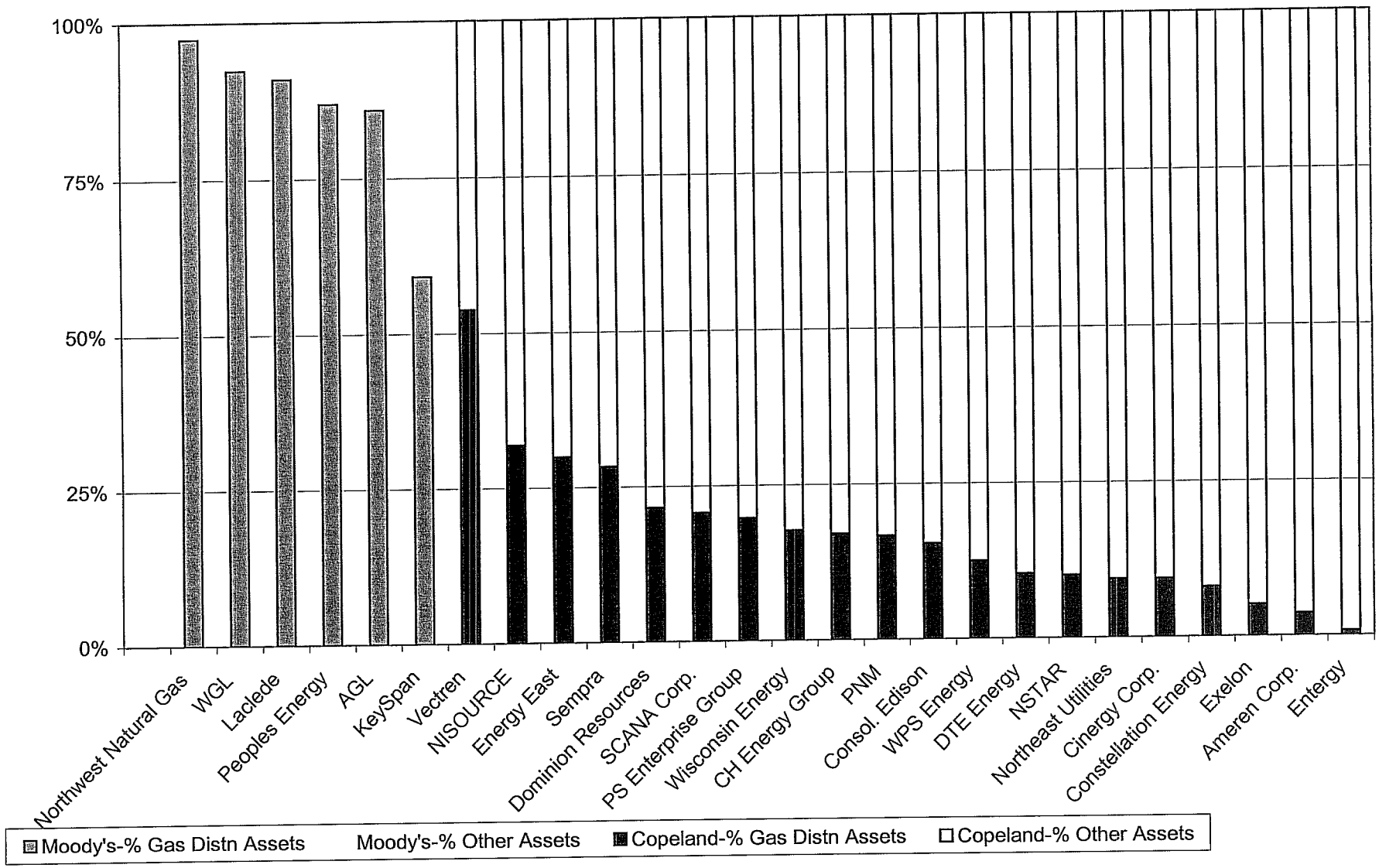


Exhibit No. ___(JSG-4)
Page 3 of 4

Montana-Dakota Utilities Co.

Percent of Revenues Associated With Gas Distribution Operations

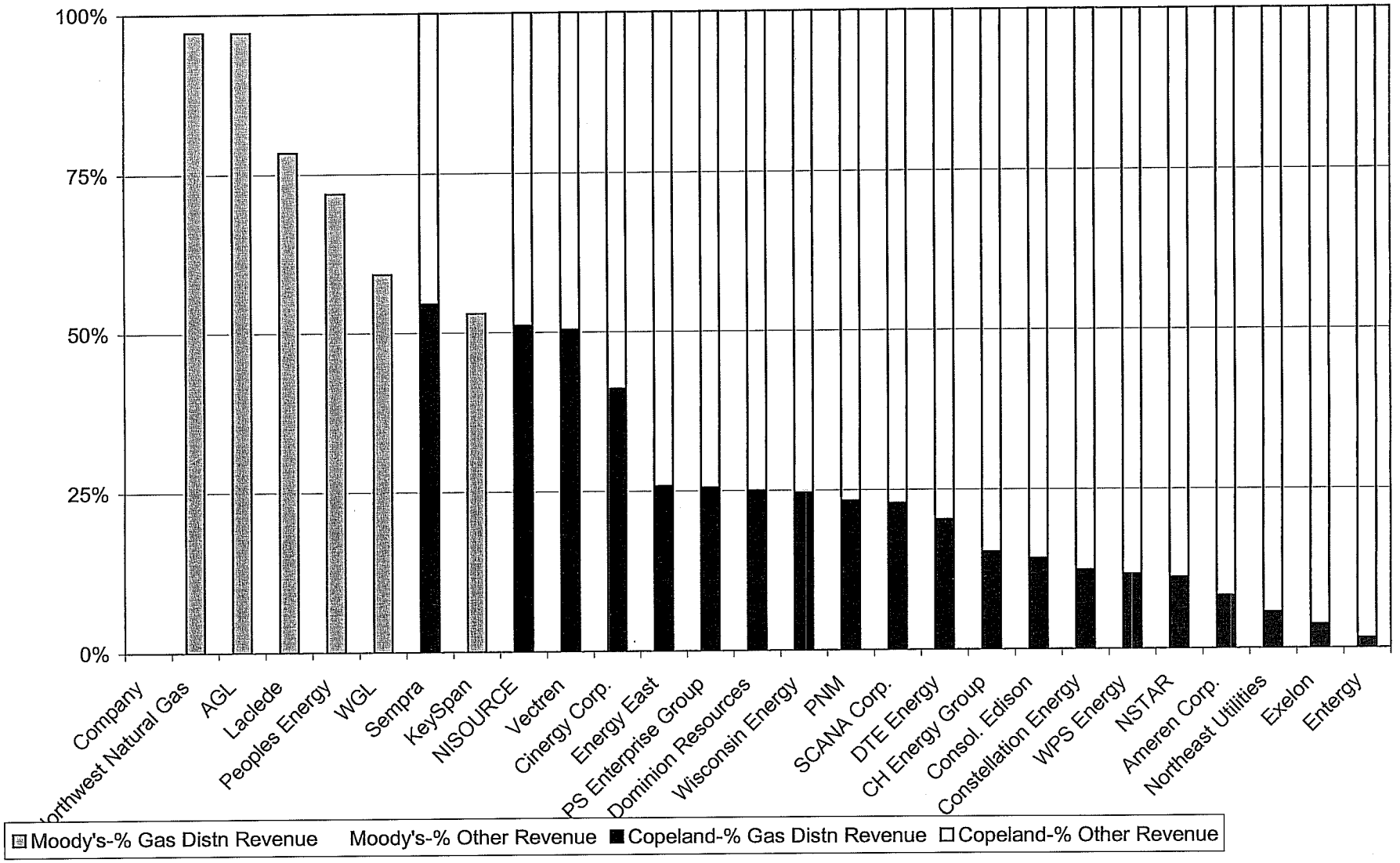


Exhibit No. ___(JSG-4)
Page 4 of 4

Montana-Dakota Utilities Co.

Allowed Return Based on Arithmetic Average Historical Results Produces Expected Return

Historical Return in the Beginning	**15.000%**	**14.709%**	0.1000

Year	**Arithmetic** Allowed Return	Investment Value	One-Year Actual Return	3-Year Results: Arithmetic Mean	Geometric Mean	Standard Deviation
0		1.00				
1	15.00%	1.15	15.000%			
2	15.00%	1.44	25.000%			
3	15.00%	1.51	5.000%	15.000%	14.709%	0.1000
4	15.00%	1.74	15.000%			
5	15.00%	2.17	25.000%			
6	15.00%	2.28	5.000%	15.000%	14.709%	0.1000
7	15.00%	2.62	15.000%			
8	15.00%	3.27	25.000%			
9	15.00%	3.44	5.000%	15.000%	14.709%	0.1000
10	15.00%	3.95	15.000%			
11	15.00%	4.94	25.000%			
12	15.00%	5.19	5.000%	15.000%	14.709%	0.1000
13	15.00%	5.97	15.000%			
14	15.00%	7.46	25.000%			
15	15.00%	7.83	5.000%	15.000%	14.709%	0.1000
16	15.00%	9.01	15.000%			
17	15.00%	11.26	25.000%			
18	15.00%	11.82	5.000%	15.000%	14.709%	0.1000
19	15.00%	13.60	15.000%			
20	15.00%	17.00	25.000%			
21	15.00%	17.85	5.000%	15.000%	14.709%	0.1000
22	15.00%	20.52	15.000%			
23	15.00%	25.66	25.000%			
24	15.00%	26.94	5.000%	15.000%	14.709%	0.1000
25	15.00%	30.98	15.000%			
26	15.00%	38.72	25.000%			
27	15.00%	40.66	5.000%	15.000%	14.709%	0.1000
28	15.00%	46.76	15.000%			
29	15.00%	58.45	25.000%			
30	15.00%	61.37	5.000%	**15.000%**	**14.709%**	0.1000
30-Year Average				15.000%	14.709%	0.0830

NOTE: Allowed Return Based on Average Arithmetic Return for the most recent 3 years.

Montana-Dakota Utilities Co.

Allowed Return Based on Geometric Average
Historical Results Produces Less Than Expected Return

Historical Return in the Beginning	**15.000%**	**14.709%**	0.1000

				3-Year Results:		
Year	**Geometric** Allowed Return	Investment Value	One-Year Actual Return	Arithmetic Mean	Geometric Mean	Standard Deviation
0		1.00				
1	14.71%	1.15	14.709%			
2	14.71%	1.43	24.709%			
3	14.71%	1.50	4.709%	14.709%	14.418%	0.1000
4	14.42%	1.71	14.418%			
5	14.42%	2.13	24.418%			
6	14.42%	2.23	4.418%	14.418%	14.126%	0.1000
7	14.13%	2.54	14.126%			
8	14.13%	3.15	24.126%			
9	14.13%	3.28	4.126%	14.126%	13.833%	0.1000
10	13.83%	3.74	13.833%			
11	13.83%	4.63	23.833%			
12	13.83%	4.81	3.833%	13.833%	13.539%	0.1000
13	13.54%	5.46	13.539%			
14	13.54%	6.74	23.539%			
15	13.54%	6.98	3.539%	13.539%	13.245%	0.1000
16	13.24%	7.91	13.245%			
17	13.24%	9.74	23.245%			
18	13.24%	10.06	3.245%	13.245%	12.950%	0.1000
19	12.95%	11.36	12.950%			
20	12.95%	13.97	22.950%			
21	12.95%	14.38	2.950%	12.950%	12.654%	0.1000
22	12.65%	16.20	12.654%			
23	12.65%	19.87	22.654%			
24	12.65%	20.40	2.654%	12.654%	12.357%	0.1000
25	12.36%	22.92	12.357%			
26	12.36%	28.04	22.357%			
27	12.36%	28.71	2.357%	12.357%	12.060%	0.1000
28	12.06%	32.17	12.060%			
29	12.06%	39.26	22.060%			
30	12.06%	40.07	2.060%	**12.060%**	**11.761%**	0.1000
30-Year Average				13.389%	13.091%	0.0835

NOTE: Allowed Return Based on Average Geometric Return for the most recent 3 years.

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

Before the Public Utilities Commission of South Dakota

Docket No. NG02-011

Rebuttal Testimony
of
Don M. Hamann

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

A. Yes. My name is Don M. Hamann, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Gas Supply Manager for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Gas Supply Manager?

A. As Gas Supply Manager, I am responsible for developing and maintaining the company's gas supply and gas transportation portfolios, demand side planning and forecasting, gas control, and monitoring and contract administration of the interruptible customers.

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

A. I graduated from the South Dakota School of Mines and Technology, Rapid City, South Dakota in 1971 with a Bachelor of Science Degree in Mechanical Engineering. I began my career with Montana-Dakota in June of 1971 as a Gas Distribution Engineer in the Black Hills Division. During my career with the

1 company I have also held the positions of Gas Distribution
2 Engineer, Staff Engineer, Assistant Division Manager and Division
3 Manager. I assumed my present position in July 1989.
4 Q. Have you testified in other proceedings before regulatory bodies?
5 A. Yes. I have presented testimony before the Montana Public
6 Service Commission and the Wyoming Public Service Commission.
7 Q. What is the purpose of your testimony?
8 A. The purpose of my testimony is to address the valuation methods
9 used by Mr. Bettmann to determine weather normalized volumes. My
10 testimony shows that Mr. Bettmann incorrectly used heating degree days
11 (HDD) based on an average daily temperature of 65 degrees and
12 incorrectly determined and applied the baseload use in his calculation of
13 adjustments used to represent weather normalized volumes.
14 Q. Would you please comment on Mr. Bettmann's rationale for the use of
15 HDD's based on 65 degrees?
16 A. Mr. Bettmann did not provide any rationale but simply states "The
17 65 degree day basis was used because it is generally accepted as a
18 temperature level where a building requires heating if the outside
19 temperature drops below that point."
20 Q. Is Mr. Bettmann's assessment true?
21 A. No. While 65 degrees was generally considered the temperature
22 level where a building required heating several years ago, it is not a
23 correct assumption today. The American Society of Heating Refrigerating

1 and Air Conditioning Engineers (ASHRAE) has recognized for several
2 years that the use of heating degree days with a base of 65 degrees is no
3 longer appropriate. The 2001 ASHRAE Handbook states
4 "**Variable-Base Annual Degree-Days.** The calculation of Q_h from
5 degree-days DD_h (t_{bal}) depends on the value of t_{bal}. This value
6 varies widely from one building to another because of widely
7 differing personal preferences for thermostat settings and setbacks
8 and because of different building characteristics. In response to the
9 fuel crises of the 1970s, heat transmission coefficients have been
10 reduced, and thermostat setback has become common. At the
11 same time, the energy use by appliances has increased. These
12 trends all reduce t_{bal} (Fels and Goldberg 1986). Hence, in general,
13 degree days with the traditional base 65°F are not to be used."
14 Q. If a 65 degree day basis is not appropriate, how do you determine which
15 temperature level to use?
16 A. The best method is to plot the daily natural gas sendout vs. the
17 daily average temperature to determine the point at which energy is
18 required for heating.
19 Q. Have you completed this type of analysis of the load profile specific to the
20 Black Hills area?
21 A. Yes. Several studies have been completed that indicate a base
22 temperature of 60 degrees is more accurate than 65 degrees. The results
23 of one of these studies are shown on Exhibit No.___(DMH-1). This graph

shows the combined daily sendout into the Rapid City, Sturgis, Deadwood, Lead, Spearfish, and Belle Fourche distribution systems plotted versus the average daily temperature for Rapid City for the period July 2001 through June 2002. The sendout includes the volumes delivered through the town border stations less any volumes that were delivered to the transportation customers. This data provides a very good look at approximately 90 percent of the firm natural gas usage in the Black Hills area.

Q. What does this graph show?

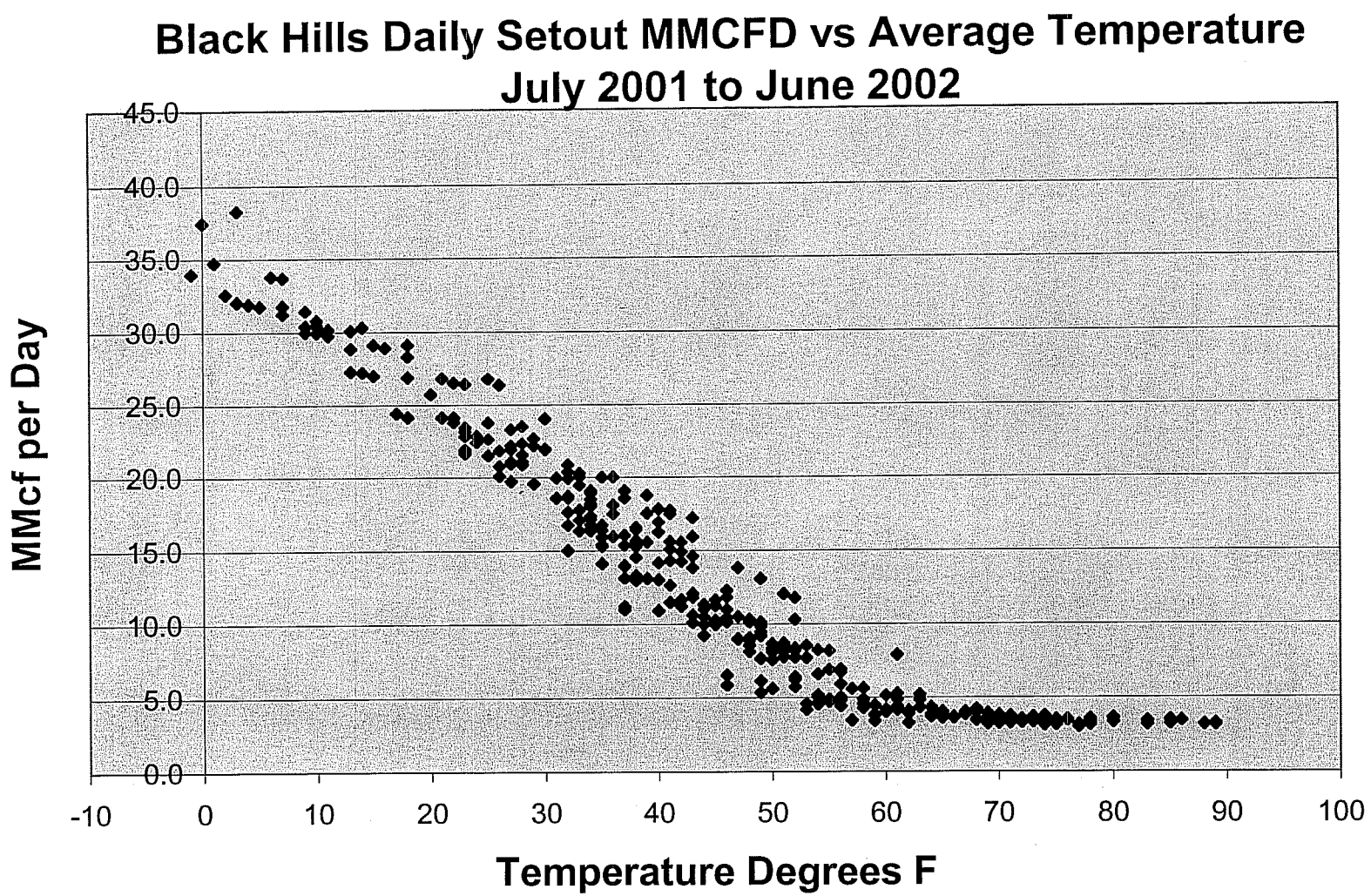
A. This graph clearly shows that the natural gas use related to temperature does not begin until the average daily temperature drops below 60 degrees Fahrenheit.

Q. Are there other methods available to determine whether the degree day basis used is representative of the temperature level where heating begins?

A. Yes. A linear regression analysis can be used with monthly consumption and HDD data to determine which temperature base produces the highest correlation and the best load curve that represents the data. As an example, a comparison was made for the sales volumes in the residential small meter category compared against degree days with a temperature base of 60 degrees and 65 degrees as shown in Exhibit No.___(DMH-2). The results indicate a correlation of 0.9895 with a temperature base of 60 degrees and a correlation of 0.9834 with a

1 temperature base of 65 degrees. Although, both of these analyses
2 produce high levels of correlation, the analysis with a temperature base of
3 60 degrees produces a constant or baseload use of 59,210 dk per month
4 while the analysis with a temperature base of 65 degrees produces a
5 constant of 39,948 dk per month. Comparing this to the actual data, the
6 minimum use, which occurred in Aug 2001, was 61,193 dk. It is evident
7 that the results using a temperature base of 60 degrees fit the actual data
8 better than the results using a temperature base of 65 degrees.
9 Q. Have you reviewed Mr. Bettmann's determination of the Baseload use?
10 A. Yes. Mr. Bettmann used a 3-month average to determine the
11 baseload use rather than the lowest month or any month where it was
12 apparent that there was no weather related use. Mr. Bettmann's states,
13 "Generally, these months contain very few normal HDD's and even the
14 slight variation on weather can cause a significant adjustment in the
15 weather normalization calculation."
16 Q. What is wrong with this methodology?
17 A. By using a 3-month average Mr. Bettmann calculates a baseload or
18 non-heating load that is higher than actually occurred. While this
19 assumption may not have a significant effect on these 3 months in this
20 particular test year, it does effect the weather normalization calculations
21 for the other 9 months. This occurs because the use of a higher than
22 actual non-heating load results in subtracting more baseload volumes
23 from the heating months, thereby, reducing the total temperature sensitive

1 volumes subject to weather normalization. As a result, Mr. Bettmann's
2 models underestimate the total volumes that should have been normalized
3 for weather.
4 Q. What is the overall effect of weather normalization models using a heating
5 degree day based on 65 degrees rather than 60 degrees?
6 A. Generally, models based on 65 degree day base will produce
7 higher results when weather is colder than normal and lower results when
8 the weather is warmer than normal. The graph shown in Exhibit No.___
9 (DMH-3) shows the results of the normalization of the firm volumes
10 delivered to the Rapid City Border Station. This data represents each 12-
11 month ending cycle from January 1997 through December 2002. This
12 graph shows the normalization results using a degree day base of 60
13 degrees and 65 degrees as well as the 12-month ending actual deliveries.
14 It is evident from this graph, that when the actual deliveries were higher
15 than normal, the normalization results based on 65 degrees were higher
16 than those based on 60 degrees, and when the actual deliveries were less
17 than normal the results based on 65 degrees were less than those based
18 on 60 degrees. The normalization calculations based on 60 degrees
19 provide a better estimate over time than those based on 65 degrees.
20 Q. Does this conclude your testimony?
21 A. Yes, it does.



Docket No. NG02-011
Exhibit No.___(DMH-1)

Residential - Small Meters

Using a Temperature Base of 65 Degrees F

Month	Customers	Dk Sales	Actual HDD65	Normal BPDD65
Jul-01	34,278	68,510	59	49
Aug-01	34,326	61,193	0	7
Sep-01	34,514	66,967	64	90
Oct-01	34,825	134,934	248	274
Nov-01	35,107	225,914	578	723
Dec-01	35,137	368,490	928	1,087
Jan-02	35,243	479,975	1,143	1,271
Feb-02	35,285	429,024	1,091	1,258
Mar-02	35,336	473,644	1,118	974
Apr-02	35,242	357,474	991	763
May-02	35,200	230,370	571	493
Jun-02	35,121	110,862	243	222
Total		3,007,357	7,034	7,211

Linear Regression Analysis

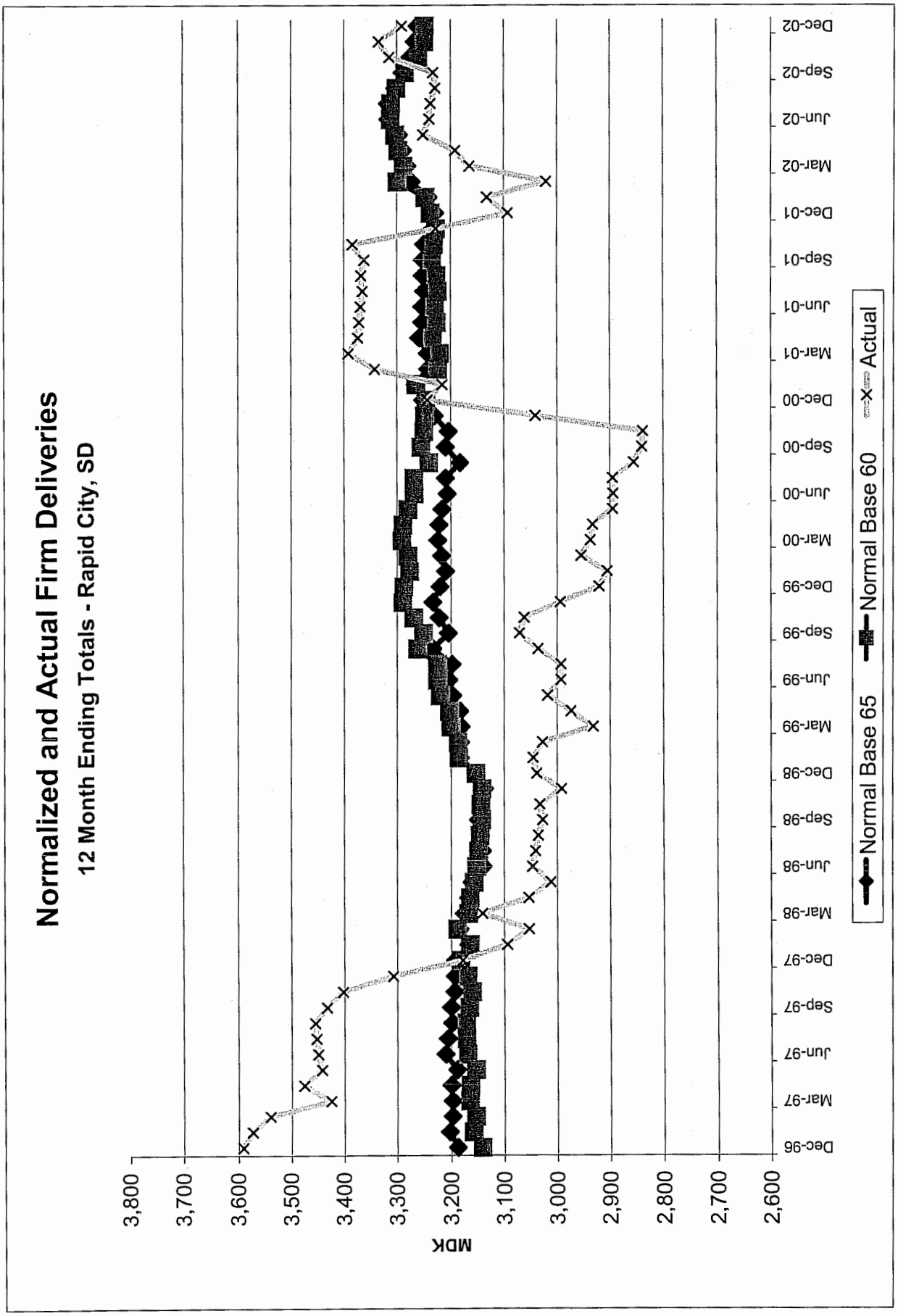
Base Load Constant	Heating Coefficient Dk per HDD	Correlation R squared
39,948	359.4	0.9834

Using a Temperature Base of 60 Degrees F

Month	Customers	Dk Sales	Actual BPDD60	Normal BPDD60
Jul-01	34,278	68,510	21	20
Aug-01	34,326	61,193	0	1
Sep-01	34,514	66,967	27	42
Oct-01	34,825	134,934	149	173
Nov-01	35,107	225,914	418	569
Dec-01	35,137	368,490	774	943
Jan-02	35,243	479,975	990	1,120
Feb-02	35,285	429,024	937	1,096
Mar-02	35,336	473,644	977	823
Apr-02	35,242	357,474	846	618
May-02	35,200	230,370	422	355
Jun-02	35,121	110,862	147	111
Total		3,007,357	5,708	5,871

Linear Regression Analysis

Base Load Constant	Heating Coefficient Dk per HDD	Correlation R squared
59,210	402.4	0.9895


Normalized and Actual Firm Deliveries
12 Month Ending Totals - Rapid City, SD
MDK
3,800
3,700
3,600
3,500
3,400
3,300
3,200
3,100
3,000
2,900
2,800
2,700
2,600
Dec-96
Mar-97
Jun-97
Sep-97
Dec-97
Mar-98
Jun-98
Sep-98
Dec-98
Mar-99
Jun-99
Sep-99
Dec-99
Mar-00
Jun-00
Sep-00
Dec-00
Mar-01
Jun-01
Sep-01
Dec-01
Mar-02
Jun-02
Sep-02
Dec-02
Normal Base 65
Normal Base 60
Actual

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

Before the Public Utility Commission of South Dakota

Docket No. NG02-011

Rebuttal Testimony
of
Rita A. Mulkern

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

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

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

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

7 Q. Are you the same Rita A. Mulkern who filed direct testimony earlier in this
8 proceeding?

9 A. Yes, I am.

10 Q. What is the purpose of your rebuttal testimony?

11 A. The purpose of my rebuttal testimony is to address certain
12 adjustments proposed by Mr. Keith Senger, Mr. David Jacobson and Ms.
13 Michelle Farris of the South Dakota Public Utilities Commission Staff
14 (Staff) to Montana-Dakota's filed position.

15 Q. Do you have any general comments about the Staff's overall position?

16 A. Yes. The Staff, in this docket, has chosen to ignore ARSD
17 20:10:13:44 and uses a historical test period in a manner that contravenes
18 the intent of matching revenues and costs and misstates the Company's
19 method of applying the known and measurable changes.

1 Q Does Montana-Dakota's filing comply with the provisions of ARSD
2 20:10:13:44?
3 A Montana-Dakota's projected test year is in compliance with ARSD
4 20:10:13:44, which states that "Proposed adjustments to book costs shall
5 be shown separately and shall be fully supported, including schedules
6 showing their derivation, where appropriate. However, no adjustments
7 shall be permitted unless they are based on changes in facilities,
8 operations, or costs which are known with reasonable certainty and
9 measurable with reasonable accuracy at the time of the filing and which
10 will become effective within 24 months of the last month of the test period
11 used for this section and unless expected changes in revenue are also
12 shown for the same period."
13 Q How does Montana-Dakota's 2003 projected test year comply with the
14 known and measurable aspects of the rule?
15 A Montana-Dakota filed this case on December 30, 2002 using a
16 twelve months ending June 30, 2002 base period and making adjustments
17 to that base period to arrive at a calendar year 2002 and calendar year
18 2003 test period. A calendar year 2003 is certainly within the required
19 time frame of 24 months after the end of the base period. The projections
20 Montana-Dakota made to revenue, expense and rate base do fall within
21 the parameters of being known with reasonable certainty and measurable
22 with reasonable accuracy. All of the adjustments "match", that is the plant
23 levels, customer (revenue) levels and expense levels are all tied together

1 for the 2003 calendar year. Each adjustment is identified and shown
2 separately in the Statements filed as part of the case, and workpapers that
3 support the derivation of each adjustment were provided. While the
4 adjustments have been labeled as "projections", those projections were
5 based on actual data or data that was known and measurable at the time
6 of the filing. Staff seems to have disallowed most adjustments because
7 they have been called "projections" rather than "pro forma adjustments".
8 The Staff appears to be of the opinion that a "budget" number is a broad
9 estimate lacking any supporting detail, which is far from the truth.
10 Montana-Dakota's capital and expense budgets, which were both used in
11 part in this case, are developed in detail, scrutinized closely, approved by
12 the Board of Directors and the responsible department manager/head is
13 accountable for any deviations from the budgeted amount.
14 The Staff, on the other hand, started with the June 30, 2002 base
15 period and made several adjustments, mostly to reflect a few events that
16 had occurred by the time of the filing. In addition, despite emphasizing the
17 importance of matching, Staff's cost of service does not match, that is the
18 revenues, expenses and rate base are not correlated.
19 Q. Why is the test period proposed by Montana-Dakota the best one to use?
20 A. The rates resulting from the final outcome in this case will be
21 implemented in the summer of 2003. As stated by Mr. Senger in his
22 testimony on page 4, "The objective of a rate case is to establish a per unit
23 charge to recover the cost of service that reflects the appropriate matching

1 of costs and investment to the revenue generated by that per unit charge."
2 Therefore, the rates charged in 2003 should match the investment level
3 and cost levels being experienced when the rates become effective. The
4 Staff's position, a June 30, 2002 test period, fails to match the proposed
5 revenues with the cost levels at the time the rates will go into effect by
6 almost a year. In addition, the Staff's position will contribute immensely to
7 regulatory lag and deny Montana-Dakota the opportunity to earn its
8 authorized return.
9 I will address the adjustments made by Mr. Senger, Mr. Jacobson
10 and Ms. Farris individually.
11 Q. What is Mr. Senger proposing in this case?
12 A. Mr. Senger is essentially proposing to use a historic test period with
13 limited adjustments and his position is contrary to general ratemaking
14 principles. On page 5, line 21 of his testimony Mr. Senger states, "Again,
15 projections, forecasts, assumptions and estimates are all speculative.
16 They are certainly not known. Additionally, many of the projections,
17 forecasts, assumptions and estimates are made with little regard to the
18 revenue/cost relationships; therefore, they are not measurable."
19 Q. Is that correct?
20 A. No, it is not. ARSD 20:10:13:44 states that the adjustments must
21 be "known with *reasonable* certainty and measurable with *reasonable*
22 accuracy" (emphasis added). The adjustments that Montana-Dakota
23 made to the June 30, 2002 base period are not speculative; they match

1 revenue with expense and they are known with reasonable certainty and
2 measurable with reasonable accuracy. The Staff has taken the position
3 that the adjustments must be absolutely certain and absolutely
4 measurable, which is not in accordance with the rule.
5 Q. What adjustments did Mr. Senger make to rate base?
6 A. He made several adjustments. First, he did not allow the plant
7 additions for the period June through December 2002 and the calendar
8 year 2003. These additions to plant, shown in Statement D, are
9 specifically identified and quantified by individual project, both for
10 replacement projects and projects associated with new customers. As
11 noted earlier in my rebuttal testimony, those projects are scrutinized,
12 approved by Montana-Dakota's Senior Management and finally approved
13 by the MDU Resources Group, Inc. Board of Directors. These are known
14 and measurable adjustments that fall within the 24 month period defined in
15 ARSD 20:10:13:44. Such plant additions are necessary in order to match
16 the investment in rate base to the time period the rates will go into effect.
17 Mr. Senger proposes using the historical average June 30, 2002
18 plant levels adjusted to annualize certain plant items, which he derives by
19 computing monthly averages and then proceeds to average the averages
20 to arrive at adjusted plant. This is incorrect for two reasons. First, a
21 thirteen month average is traditionally used when calculating a normalized
22 balance for items that fluctuate significantly during the year, so that the
23 timing of the test period does not affect the value of the balance. Items

1 that typically are calculated using a thirteen month balance are materials
2 and supplies, which vary with the construction season, or prepayments,
3 which fluctuate with the expiration date of the prepayment. Thirteen
4 month balances, especially based on monthly averages, are not generally
5 used in developing plant in service and reserve for depreciation as they do
6 not fit the fluctuating pattern. Furthermore, calculating an average of
7 average balances serves no purpose other than being a mathematical
8 exercise that understates the valuation of assets in place to provide
9 service.
10 Second, the net effect of Mr. Senger's approach to plant in service,
11 averaging average balances, results in an average December 31, 2001
12 plant level, which is not an appropriate level to use in setting rates in mid-
13 2003.
14 Q. What other adjustments did Mr. Senger make?
15 A. Mr. Senger also excluded Montana-Dakota's adjustments that were
16 related to the plant additions, such as reserve for depreciation,
17 depreciation expense and ad valorem taxes. He also eliminates the
18 increase in customers and resulting volumes and the portion of the
19 postage increase pertaining to the additional customers. Mr. Senger's
20 adjustments are not appropriate as he disallows Montana-Dakota's
21 adjustments based on an invalid interpretation of ARSD 20:10:13:44.
22 Q. Are there other effects of Mr. Senger's adjustments?

1 A. Yes. Montana-Dakota proposed, as described in the direct
2 testimony of Mr. C. Wayne Fox at page 7, lines 12-22, to own all service
3 lines on a prospective basis and the plant additions included in this case
4 reflect the costs of owning all new and replacement service lines. If the
5 Commission does not allow the investment associated with ownership of
6 service lines, Montana-Dakota will be required to withdraw its request
7 regarding service line ownership.
8 Q. Turning now to Mr. Jacobson's testimony, do you have any comments on
9 his testimony?
10 A. I will address the adjustments that Mr. Jacobson made to insurance
11 expense, labor and payroll tax expense and cash working capital. On
12 page 3 of his testimony, Mr. Jacobson did not allow Montana-Dakota's
13 insurance expense level, which is the 2003 calendar year level, because
14 he views it as speculative. First, the amounts projected by Montana-
15 Dakota are not speculative. The amounts budgeted for 2003 were
16 developed by the Risk Management Department, based on their expertise
17 and information provided by the insurance carriers. Significant increases
18 have been the norm the last few years in the insurance industry and those
19 increases are reflected in the 2003 level. While Mr. Jacobson attempted
20 to update the per books amount by using the twelve months ending
21 February 28, 2003, his adjustment will not result in matching costs with the
22 timing of additional revenues. As noted by Mr. Jacobson, most of the
23 insurance policies expire in October or December of each year. Therefore

1 using the twelve months ending February 28, 2003 fails to take into
2 account the new premium levels, while the Company's projection does.
3 Mr. Jacobson also failed to recognize the 2003 level of labor
4 expense and related payroll taxes for the Company but instead merely
5 annualized the May 2002 union increase. Montana-Dakota provided the
6 detailed procedure used to determine the labor increase each year in
7 data Response No. 2-29. Mr. Jacobson characterized Montana-Dakota's
8 2003 labor expense levels as being "fraught with uncertainty" and that the
9 Company's proposal does not take into account employee efficiency.
10 Again, Mr. Jacobson is incorrect. The wage levels incorporated in the
11 projected 2002 and 2003 labor expense were from the 2002 and 2003
12 budgets. The wage increases underlying the budgets went into effect on
13 January 1, 2002 and January 1, 2003 for the non-union employees and on
14 May 1, 2002 and May 1, 2003 for the union employees. Those wage
15 increases have actually taken place and are well within the 24 month
16 period specified in ARSD 20:10:13:44. With regard to potential employee
17 efficiencies, Mr. Fox, in his direct testimony, lists some of the efficiencies
18 Montana-Dakota has implemented. In addition, the budgeting process
19 used by Montana-Dakota takes into account employee efficiencies.
20 Q. On page 5 of his testimony, Mr. Jacobson used the benefits expense for
21 the twelve months ending March 31, 2003. Why doesn't that update
22 provide a good matching of expenses?

1 A. While using the twelve months ending March 31, 2003 is more
2 recent than June 30, 2002, it still does not reflect current conditions. For
3 example, with regard to pension and post-retirement expenses, Montana-
4 Dakota receives an actuarial report each year from Towers Perrin in the
5 fall that sets forth the amounts for Montana-Dakota to record for the next
6 calendar year. Therefore, using a twelve months ending March 31, 2003
7 does not reflect the current costs but places more weight on the historical
8 costs, which are not representative of the time period the new rates will go
9 into effect. Once again it gets back to "known with reasonable certainty
10 and measurable with reasonable accuracy." Montana-Dakota has used
11 the Towers Perrin study for many years as the basis for the amounts
12 recorded for pension and postretirement costs and it is the basis for the
13 expenses currently being recorded. There is no reason to stop at March
14 31, 2003.
15 Q. Did Mr. Jacobson make any adjustments to rate base?
16 A. Mr. Jacobson made an adjustment to rate base for cash working
17 capital. He did not perform a lead lag study in order to justify this
18 adjustment but updated a study from the previous case, which itself was
19 an update of a previous case, etc. The last time a complete lead lag study
20 was completed was in Docket No. F-3370 and was for the twelve months
21 ending June 30, 1980. It is not appropriate to base an adjustment on a
22 June 30, 1980 study that has merely been updated over a 20+ year
23 period.

1 Q. Would you address the adjustments made by Ms. Farris?

2 A. Yes. I will address several adjustments made by Ms. Farris. First,
3 Ms. Farris eliminated dues paid to various Chambers of Commerce in
4 South Dakota as she claims that such dues are not necessary to provide
5 safe and reliable service. Montana-Dakota is a corporate citizen, and as
6 such, is and needs to be active in the communities that it serves. Being a
7 member of the local Chambers of Commerce is an important part of being
8 a member of the community and in today's environment, belonging to
9 organizations such as the Chamber is required and Montana-Dakota
10 should not be penalized for belonging to such organizations.

11 Ms. Farris also eliminated institutional advertising on the premise
12 that it only serves to enhance the image of Montana-Dakota. Again,
13 Montana-Dakota is part of the communities in which it serves and
14 advertising in the local school yearbooks, newspapers, community
15 programs and other things is key to participation. The advertising benefits
16 the communities and today it is appropriate to include these types of
17 advertising in expense.

18 On page 3 of her testimony, Ms. Farris excluded the $1,929 of
19 expense that is related to working with community/economic development
20 groups. The expense is not providing funding to any economic
21 development groups, as Ms. Farris seems to imply in her testimony on
22 page 3. It is part of Montana-Dakota employees' job responsibilities to
23 provide information to and work with communities and economic

1 development groups, just as it is their responsibility to work with other
2 potential customers. It is not appropriate to exclude these expenses just
3 because they are labeled "economic development."
4 Finally, Ms. Farris used a five-year amortization of rate case
5 expense instead of the three-year amortization period used by the
6 Company. If the Commission accepts the amortization period proposed
7 by the Staff, then the unamortized rate case balance should be included in
8 rate base.
9 Q. Would you please summarize your testimony?
10 A. Yes. The Staff has erroneously applied the terms of ARSD
11 20:10:13:44, and by doing so results in a mismatch between current
12 revenue, expense and investment levels and Staff's proposed revenue
13 requirement. Montana-Dakota's proposed 2003 calendar year test period
14 complies with ARSD 20:10:13:44 and matches revenue, expense and
15 investment levels to the time that new rates will go into effect.
16 Q. Does that complete your rebuttal testimony?
17 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. NG02-011

Rebuttal Testimony
of
Richard A. Espeland

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

2 A. My name is Richard A. Espeland. My business address is 918 East
3 Divide Avenue, Bismarck, ND 58503.

4 Q. What is your position?

5 A. I am Vice President – Human Resources for MDU Resources
6 Group, Inc. (MDU Resources).

7 Q. Are you the same Richard A. Espeland who filed direct testimony earlier in
8 this proceeding?

9 A. Yes, I am.

10 Q. What is the purpose of your rebuttal testimony?

11 A. The purpose of my rebuttal testimony is to address the adjustment
12 proposed by Mr. David Jacobson of the South Dakota Public Utilities
13 Commission Staff (Staff) to the inclusion of the Supplemental Income
14 Security Plan (SISP).

15 Q. What is Mr. Jacobson's position with regard to SISP?

16 A. Mr. Jacobson recommends against rate recovery for SISP costs
17 because: (1) the staff has allowed rate recovery of other parts of Montana-
18 Dakota's executive compensation, therefore it is reasonable to have

1 stockholders of MDU Resources fund SISP; and (2) SISP does not
2 contribute to an objective of providing lower salaried employees with a
3 larger percentage of salary replacement through retirement benefits than
4 for higher salaried employees.
5 Q. Do you agree with Mr. Jacobson's opinion?
6 A. No. I disagree with both aspects of Mr. Jacobson's analysis
7 regarding SISP.
8 Q. Please address Mr. Jacobson's position that stockholders of MDU
9 Resources Group should fund SISP because the Staff has allowed rate
10 recovery for other portions of Montana-Dakota's executive compensation.
11 A. I would first like to respond to Mr. Jacobson's observation that
12 based on aspects of other portions of executive compensation such as
13 bonuses, the Key Employee Stock Option Plan, and the Executive Long
14 Term Incentive Plan, stockholder welfare is a major concern of senior
15 management. As I stated in my direct testimony, Montana-Dakota's key
16 employees have enabled it to streamline operations, reduce costs and
17 employee numbers, implement new technologies and keep Montana-
18 Dakota's rates competitive. Although stockholder welfare is an aspect of
19 any corporate executive's responsibility, that responsibility is met through
20 the efficient and visionary management of the business in a manner that
21 allows its products and services to be competitive in the market. The
22 company's customers are direct beneficiaries of competitive products and
23 services. The cost of recruiting and retaining management talent needed

1 to operate in a competitive manner is part of the company's cost of doing
2 business and must be included in the prices of its products and service.
3 Montana-Dakota's utility business is no different.
4 SISP is a part of the total compensation package for Montana-
5 Dakota's key employees. The "Competitive Analysis" report prepared by
6 Towers Perrin for MDU Resources showed that the compensation
7 package is not only reasonable but actually conservative when compared
8 to similar companies. Because the costs of Montana-Dakota's executive
9 compensation are reasonable, which is not disputed by Mr. Jacobson,
10 Montana-Dakota is entitled to full recovery of those costs in its rates.
11 Montana-Dakota should not be denied recovery of one portion of a
12 legitimate cost of providing service simply because the Staff has
13 recognized the legitimacy of other portions of that cost for inclusion in rate
14 recovery. Ironically, while Mr. Jacobson recognizes that those parts of
15 executive compensation that are tied to corporate performance, such as
16 bonuses, are appropriately recovered in rates, he nonetheless
17 recommends denial of rate recovery for SISP benefits which are not
18 directly tied to corporate performance.
19 Mr. Jacobson's position of requiring stockholders to absorb the cost
20 of SISP because other portions of executive compensation are included in
21 rates has the direct effect of reducing net income to shareholders and
22 thereby effectively denying them the opportunity to earn the rate of return
23 found reasonable by the Commission. Adopting Mr. Jacobson's position

1 would encourage replacement of SISP with increases in executive base
2 salary and other benefits which are included in rate recovery. This would
3 actually increase costs to ratepayers in order to provide the same level of
4 financial compensation to employees.
5 Q. Please address the second aspect of Mr. Jacobson's opinion that SISP
6 does not contribute to an objective of providing lower salaried employees
7 with a larger percentage of salary replacement through retirement
8 benefits.
9 A. As I explained in my direct testimony, MDU Resources tries to
10 provide different target levels of replacement income based on the level of
11 employee base compensation – 80% at lower income levels and 50% at
12 higher income levels. As shown on Exhibit No. ____ (RAE-2) to my direct
13 testimony, the current retirement benefits for lower salaried employees
14 meet the 80% target. The 50% target for higher salaried employees,
15 however, would not be met under the existing retirement benefits without
16 SISP. SISP was never intended to contribute to the objective of providing
17 lower salaried employees with retirement benefits equal to 80% of salary
18 because that objective is already met with other retirement benefits which
19 cannot be provided in the same relative degree to higher compensated
20 employees. SISP was intended to address the other piece of MDU
21 Resources' objective by providing 50% retirement replacement income to
22 higher salaried employees. This is a reasonable and accepted
23 compensation objective, the cost of which should be included in rate

1 recovery in the same manner that the costs of retirement benefits for lower

2 salaried employees are included in rate recovery.

3 Q. Does that conclude your rebuttal testimony?

4 A. Yes it does.

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

Before the Public Utility Commission of South Dakota

Docket No. NG02-011

Rebuttal Testimony
of
Alvin J. Feist

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

3 A. My name is Alvin J. Feist. My business address is 918 East Divide
4 Avenue, Bismarck, North Dakota 58501.

5 Q By whom are you employed and in what capacity?

6 A. I am Tax Planning Director of MDU Resources Group, Inc. (MDU
7 Resources), of which Montana-Dakota Utilities Co. (Montana-Dakota) is
8 the energy distribution division.

9 Q. Would you please describe your responsibilities as Tax Planning Director?

10 A. My responsibilities include providing assistance with the tax
11 compliance, planning and financial reporting for all federal and state
12 income taxes for MDU Resources Group, Inc. and its subsidiaries.

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

15 A. I graduated Summa Cum Laude from the University of North
16 Dakota in 1977, receiving a Bachelor of Science degree in Business
17 Administration, with a major in Accounting. I am a Certified Public
18 Accountant having received my certificate in 1978, and I am a member of

1 the American Institute of Certified Public Accountants and the North
2 Dakota Society of Certified Public Accountants.
3 Q. Would you please describe your work experience?
4 A. For approximately eight years, before my employment by MDU
5 Resources, I was employed by both a local and regional public accounting
6 firm, serving in a number of capacities, the most recent as Tax Supervisor.
7 In April 1985, I joined MDU Resources' Tax Department as an
8 Income Tax Analyst, a position I retained until January 1988 when I was
9 promoted to the position of Tax Manager. As Tax Manager, my
10 responsibilities included supervising the preparation and filing of all federal
11 and state income tax returns for MDU Resources and its subsidiaries.
12 This included the supervision and review of the income tax accruals for
13 Montana-Dakota. In addition, my responsibilities included the supervision
14 of the filing of the various property tax and sales tax returns for Montana-
15 Dakota. I remained in this position until October, 1998, at which time I
16 attained my current position.
17 Q. Have you previously testified in proceedings before regulatory agencies?
18 A. Yes. I have filed testimony before the Federal Energy Regulatory
19 Commission regarding income and general taxes. I have also testified
20 before the Montana Public Service Commission.
21 Q. What is the purpose of your rebuttal testimony?
22 A. The purpose of my rebuttal testimony is to address the adjustment
23 made by Mr. Robert Towers, testifying on behalf of the South Dakota

1 Public Utilities Commission Staff, to the allowance for income taxes. I am
2 also sponsoring Exhibit No.___(AJF-1) through Exhibit No. ___(AJF-5).
3 Q. Mr. Towers has indicated that Montana-Dakota does not file a separate
4 federal income tax return and is included in the filing of a consolidated
5 federal income tax return with MDU Resources and its subsidiaries.
6 Would you please briefly summarize what is involved in preparing a
7 consolidated return?
8 A. A consolidated return is prepared to report the taxable income of an
9 affiliated group of companies in lieu of such companies filing separate
10 income tax returns to report each individual company's respective taxable
11 income. The preparation of a consolidated return is described in Peel
12 Consolidated Tax Returns, § 1.1 (3rd Ed):
13 "The income for each corporation in the affiliated group is
14 calculated separately for most items. The separate calculations are
15 modified, however, by special rules for transactions among the
16 members of the group. Specified items, such as capital gains and
17 losses, are consolidated at the outset. The separate taxable
18 incomes of the members and the consolidated items are combined
19 to arrive at consolidated taxable income for the group. Finally, a
20 consolidated tax is computed on the consolidated taxable income."
21 Q. Who may file a consolidated return?
22 A. In order to be eligible for the filing of a consolidated return, the
23 corporations must be qualifying domestic corporations and the

1 corporations must meet an affiliation test involving ownership with a
2 common parent (involving ownership of at least 80 percent of the value
3 and voting power of stock). In addition, all affiliated group members
4 during the tax year must timely consent to all the consolidated return
5 regulations.
6 Q. If a group of affiliated corporations have made an election to file a
7 consolidated return, does the possibility for filing separate returns exist for
8 subsequent years?
9 A. If an election has been made to file a consolidated tax return, an
10 application can be made to discontinue the filing of a consolidated return
11 for subsequent years. A change in law or circumstances, such as a
12 change in regulatory treatment, may be considered to be an element of
13 good cause resulting in the Internal Revenue Commissioner's approval of
14 an application to discontinue the filing of a consolidated return.
15 Furthermore, as I indicated previously, a consolidated return may
16 be filed only if all corporations that were members of the affiliated group at
17 any time during the tax year timely consent to all the consolidated return
18 regulations. If a member fails to consent to the consolidated return
19 regulations, the tax liability of the affiliated members will be determined on
20 the basis of separate returns. Several new members were added to the
21 consolidated group during each of the recent years. It is possible that any
22 new affiliate could challenge the consent and argue that it has a right to
23 make an independent consent before becoming subject to the

1 consolidated return rules. As indicated above, the tax liability of the
2 affiliated members would then need to be determined on the basis of
3 separate return calculations.
4 Q. When entities consent to the filing of a consolidated return, do the
5 affiliated entities lose their identity and become what would be considered
6 a disregarded entity for tax purposes?
7 A. No. The affiliated entities continue to compute their separate
8 taxable incomes as is described above, subject to certain adjustments and
9 limitations. Each of the entities must adopt separate methods of
10 accounting, which may be inconsistent with the methods used by other
11 members. One member of the group may use the cash basis of
12 accounting while another member may report the same or similar items on
13 an accrual method. Therefore, while the tax for the consolidated group is
14 computed based upon the consolidated income, the policy of tolerance for
15 diverse accounting methods within the group and the computation of the
16 taxable income at each entity reflect a "separate entity" theory on the part
17 of the applicable tax laws and regulations.
18 Q. Would you please explain the methodology utilized by Montana-Dakota to
19 compute the federal income tax allowance in this regulatory proceeding?
20 A. The calculation of taxes for Montana-Dakota in its filing was made
21 using a "stand-alone" calculation methodology. A stand-alone calculation
22 methodology allocates the consolidated tax expense to individual
23 members through recognition of the benefits/burdens contributed by each

1 member of the consolidated group to the consolidated return. Said
2 another way, the tax benefit/burden must be given to the company that is
3 responsible for generating the income or paying the expenses giving rise
4 to a deduction or a tax burden.
5 Q. What is Montana-Dakota's basis for using the stand-alone method?
6 A. The stand-alone method allocates the consolidated tax liability in a
7 manner that is cost-justified, fair and reasonable. It recognizes the
8 principle critical for ratemaking purposes that a utility should be regulated
9 on the basis of its being an independent entity and should be considered
10 as nearly as possible on its own merits, rather than on those of its
11 affiliates. Montana-Dakota has a long established history of using the
12 stand-alone method in establishing its rates for purposes of electric and
13 gas services within Montana, North Dakota, South Dakota and Wyoming.
14 The Federal Energy Regulatory Commission (FERC) has issued several
15 decisions relying on the stand-alone method of allocating income taxes
16 among members of a consolidated group when a jurisdictional company is
17 part of a group filing a consolidated income tax return. In FERC Opinion
18 No. 173, provided as Exhibit No. ___ (AJF-1), the FERC sets forth a
19 number of arguments supporting why the stand-alone method is the
20 appropriate method of determining income taxes for a regulated entity.
21 Q. Would you please elaborate on the FERC arguments in support of the
22 stand-alone methodology?
23 A. On page 61,852 of Exhibit No. ___(AJF-1), the FERC stated:

1 ...the method the Commission has followed since 1972, is one in
2 which "a utility [is] considered as nearly as possible on its own
3 merits and not on those of its affiliates." This method is called the
4 stand-alone method, for "a stand-alone income tax allowance is
5 one that takes into account the revenues and costs entering into
6 the regulated cost of service without increase or decrease for tax
7 gains or losses related to other activities . . . " The stand-alone
8 method results in the tax allowance being equal to the tax the utility
9 would pay on the basis of its projected revenues less deductions for
10 all operating, maintenance, and interest expenses included in the
11 cost of service. In short, it results in a tax allowance equal to the tax
12 on the allowed return on equity.
13 Q. Mr. Towers has proposed that "tax savings" were realized through the
14 filing of a consolidated return. Do you agree that the losses of the
15 affiliates should be considered to be "tax savings"?
16 A. No, I do not agree. A principal advantage of filing a consolidated
17 return over filing separate returns is to reduce the administrative effort and
18 number of filings related to such tax return filings, except in the case
19 where a member of the group has deductions that exceed limitations that
20 would otherwise limit the recognition of such deductions. In the case of a
21 consolidated return involving deduction limitations for certain of its
22 members, the realization of tax benefits for such deductions are generally
23 a matter of timing for that entity, as the deduction can generally be carried

1 back to a prior year or carried over to a subsequent year. Thus, the
2 benefits of such losses would generally not be permanently lost if separate
3 returns were filed instead of a consolidated return. It is also highly likely
4 that if the member companies were not filing as a consolidated group, the
5 loss entity could likely deploy other tax planning strategies or a
6 reorganization of the corporate structure could be made in order to avoid
7 the loss of such tax benefits. It is incorrect to assume that tax losses do
8 not have value in the absence of taxable income by other entities within
9 the consolidated group. If the other entities in the consolidated group
10 would not have sufficient income to absorb the tax losses, these losses
11 could be carried forward to a year where that entity might have income
12 within the consolidated group sufficient to utilize such loss. While filing a
13 consolidated return may result in an acceleration of the realization of the
14 cash flow related to such tax benefits over what would be realized if the
15 loss entities were filing separate income tax returns, the time value of this
16 benefit is minor in relation to that of the tax benefit itself. Therefore, tax
17 benefits associated with the net operating losses of affiliates should not be
18 considered as true "tax savings" and Montana-Dakota should not be
19 considered as adding value to these losses by virtue of its being included
20 within the consolidated return.
21 Q. Does the stand-alone method ignore tax savings which are realized as a
22 result of filing a consolidated return?
23 A. No, it does not. On pages 61,852 and 61,853 of Exhibit No.

1 ___(AJF-1), the FERC indicates that the approved stand-alone
2 methodology "...does not ignore the consolidated return or the tax
3 reducing benefits the group realizes by filing such a return. Unlike a
4 separate return policy, our stand-alone policy in effect looks beneath the
5 single consolidated tax liability and analyzes each of the deductions used
6 to reduce the group's tax liability to determine the deductions for which
7 each service is responsible. It then allocates to the jurisdictional service
8 those deductions which were generated by expenses incurred in providing
9 that service. In making this allocation it is irrelevant on which member's
10 return the deductions would be reported if the group filed separate returns.
11 Instead, the test is whether the expenses that generate the deduction are
12 used to determine the jurisdictional service's rates. Put more simply, the
13 test is whether the expenses are included in the relevant cost of service.
14 If they are, the associated deductions and their tax reducing benefits will
15 be taken into account in calculating the tax allowance for that cost of
16 service. If the expenses are not, the deductions will not be taken into
17 account. In this way the tax allowance will reflect the profit the ratepayers
18 contribute to the group's consolidated taxable income."
19 On page 61,857 of Exhibit No. ___(AJF-1), the FERC discussed
20 the difficulty in applying alternative approaches to allocating taxes within a
21 consolidated group and the FERC indicated that the tax allowance for the
22 regulated entity:
23 ...should not be based on the "activities of others in the affiliated

1 group" but instead, like other costs, should be based on the
2 activities of the pipeline itself. Thus, the Commission rejected
3 methods of determining the tax allowance by allocating a pro rata
4 share of the consolidated tax liability and then adjusting that
5 amount by excluding the losses of certain affiliates. In place of
6 these methods the Commission installed the stand-alone method
7 which determines the tax allowance on the basis of the pipeline's
8 own revenue and expenses.
9 Q. Do you believe that not using the stand-alone method would result in an
10 inequitable result?
11 A. Yes. Montana-Dakota's cost of service and return on equity have
12 been computed on a stand-alone basis. Proper ratemaking policy
13 recognizes the requirement of keeping regulated and non-regulated
14 enterprises separate to the fullest practical extent. No evidence has been
15 presented which indicates that Montana-Dakota's ratepayers are bearing
16 the expenses resulting in the tax deductions at any of the affiliated
17 companies. The expenses resulting in the tax losses were incurred as a
18 result of cash outlays by the non-regulated entities and these same
19 entities should realize the tax benefits related to these costs. This
20 Commission would find it unacceptable for Montana-Dakota's ratepayers
21 to be burdened with the expenses of the affiliated companies. This
22 Commission should likewise recognize that it would be incongruous for
23 Montana-Dakota's ratepayers to be allocated the tax benefits that are

1 realized as a result of the expenses incurred by the affiliated companies.

2 It is also inequitable for Montana-Dakota's customers to share in
3 the ability of the consolidated group to reduce current taxes merely
4 because of a decision to include other affiliated loss companies within the
5 consolidated tax return or due to the organizational structure of the
6 consolidated group. The tax benefit of a non-consolidated entity's
7 separately determined tax loss is an asset of that entity. That entity
8 permanently gives up this asset by consenting to file a consolidated
9 return. It is only fair and equitable that an entity creating a tax benefit for
10 the consolidated group should be reimbursed for the tax benefit of the
11 asset that it permanently gives up by its joining in a consolidated return.

12 It should also be noted that the cash benefit received by the
13 affiliates as a result of these tax savings is not being paid by the Montana-
14 Dakota ratepayers, but essentially is being received from the government.
15 Montana-Dakota's ratepayers are not being charged any more under the
16 stand-alone methodology than they would be charged if no tax deductions
17 were available at the consolidated level from the other entities and
18 correspondingly, Montana-Dakota should not share in the benefit of the
19 affiliates' tax deductions.

20 The regulation of a utility and the rates charged its customers
21 should not be unjust, unreasonable, unduly discriminatory or preferential.
22 Consider a situation where two regulated entities exist and one regulated
23 entity recognizes consolidated tax savings in its rates, while the other

1 regulated entity supplying a similar public service does not have
2 consolidated tax savings available to it. A preferential situation will exist in
3 the rates charged by the one company to its customers as compared to
4 the rates charged by the other company. The creation of this preferential
5 situation violates sound ratemaking principles.
6 Q. Would you discuss the impact of the proposed allocation of tax savings for
7 the affiliates and the company as a whole?
8 A. As I mentioned previously, the affiliates who have incurred the
9 costs for deductions resulting in these tax benefits will not be able to
10 recover the tax benefits of such deductions to the extent such benefits are
11 allocated to the ratepayers. This would place these non-regulated
12 affiliates at a competitive disadvantage as compared to enterprises of
13 other totally non-regulated companies in similar industries. The proposed
14 approach prohibitively increases the cost of doing business and adversely
15 impacts the financial condition for a non-regulated entity if that entity is
16 unable to realize the tax benefits resulting from its expenditures for the
17 sole reason of being an affiliate of a regulated entity.
18 In addition, it is the company's shareholders who ultimately realize
19 the loss of tax benefits which are passed on to ratepayers. The
20 shareholders realize the detriment associated with the earnings impact of
21 the expenses resulting in the deductions, while not being able to realize
22 the tax benefits related to such.

1 Q. The focus of your testimony has been on consolidated tax savings. Is it
2 possible that one might realize a consolidated tax detriment?
3 A. Yes. The Internal Revenue Code permits taxpayers to claim
4 deductions for certain items which it considers "tax preferences." In the
5 event that the benefits derived from these deductions result in the
6 reduction of one's income tax beyond what would be allowed under an
7 alternative computation of the related deductions and tax, a company
8 might be required to pay an incremental tax. This tax is an "alternative
9 minimum tax" (AMT) and is paid in addition to the regular income tax
10 computed for that tax period. A credit may be claimed with respect to the
11 AMT in a later period, to the extent that the regular tax exceeds the AMT
12 computed for such period.
13 A consolidated group could have one or more members with a
14 significant amount of tax preference items and also having a relatively
15 minor amount of positive taxable income. These members might cause
16 the consolidated entity to be required to pay an AMT. As this tax is also
17 determined at the consolidated level and is reported as part of the total
18 income tax obligation of the consolidated group, the question might be
19 asked as to how this tax should be allocated? Using a stand-alone
20 approach, if the AMT was attributable to the income and expenses of the
21 non-regulated entities, the regulated entity would not be allocated a
22 portion of the AMT to the extent that the regulated entity would not have
23 incurred an AMT on a stand-alone basis.

1 Assuming the stand-alone methodology was not being applied, it is
2 assumed that this Commission would allocate the AMT on the same basis
3 as that used to allocate other income taxes. Applying the theory of Mr.
4 Towers' method of allocation to this situation, one would disregard the
5 income and expenses underlying the AMT computation and consider the
6 AMT as part of the total consolidated income tax to be allocated on a
7 proportionate basis to each of the jurisdictional and non-jurisdictional
8 operations. This could result in the allocation of little or no AMT to the
9 non-regulated entity causing the consolidated group to realize an AMT,
10 while a significant portion of the AMT might then be allocated to regulated
11 entities who, on a stand-alone basis, might not have incurred an AMT. As
12 a result, additional taxes would be allocated to ratepayers beyond that
13 which should have been allocated to them based on the income and
14 expenses of the jurisdictional operation. This would be inappropriate in
15 the event that a consolidated tax detriment is realized and is similarly
16 inappropriate in the event that there are consolidated tax savings.
17 Furthermore, as the AMT is allowable in future tax periods as a
18 credit against tax, one could argue that under the allocation method
19 proposed by Mr. Towers, the credit does not belong to any single entity
20 within the consolidated group. Instead, one would follow Mr. Towers'
21 theory that as there is only one return filed for the consolidated group, the
22 credit should be allocated in the subsequent period to all entities based on
23 the respective taxable incomes of the members of the consolidated group

1 for that subsequent year. This could result in the credit not being
2 allocated back to the entities which would have paid the AMT in the earlier
3 year, but could be allocated to entities which may have paid little or no
4 AMT previously. Thus a jurisdictional operation could be charged with the
5 AMT resulting from the deductions of a non-regulated entity in one year,
6 without receiving a credit for such amount in subsequent periods.
7 Q. Has the consolidated group ever had an AMT and, if so, how was it
8 allocated?
9 A. MDU reported an AMT on its 1989 tax return. The AMT was
10 allocated based on a stand-alone methodology. This methodology
11 averted the adverse impact to ratepayers which could have otherwise
12 resulted by applying Mr. Towers' proposed method, similar to that
13 described above.
14 Q. Have there been other taxes for prior years which would have resulted in
15 Montana-Dakota's realization of a tax detriment using the allocation
16 methodology proposed by Mr. Towers?
17 A. Yes. Prior to the current AMT, there was a tax known as a
18 ("Minimum Tax"). The consolidated group paid Minimum Tax in addition
19 to the regular income tax for the years 1979 through 1984. There was
20 also a tax known as the "Environmental Tax" which applied to the
21 consolidated group and other corporations during the years 1987 through
22 1995. The Environmental Tax was computed based on the income
23 determined for AMT purposes and reported as part of the consolidated tax

1 return. If these taxes had been allocated to Montana-Dakota and among
2 its jurisdictions using the allocation method proposed by Mr. Towers rather
3 than the stand-alone method, such methodology would have resulted in
4 the allocation of additional taxes to ratepayers over and above that
5 resulting from the income and expenses of the regulated operations.
6 Q. You previously suggested that if a different corporate structure were in
7 place, the suggested tax savings would not be available for reallocation to
8 Montana-Dakota's ratepayers. Would you please explain?
9 A. The corporate structure currently in place for the affiliated entities,
10 as well as the decision to continue to file a consolidated tax return, has
11 been determined based on the long-standing policy of this Commission
12 and the other Commissions for the jurisdictions in which Montana-Dakota
13 operates to allow a stand-alone methodology for allocation of income
14 taxes. Had this not been the case, alternatives would have been
15 considered to avoid the potential cross subsidization of the utility by the
16 affiliated entities. If this Commission were to reverse its past position on
17 the stand-alone method, this change in position would retroactively
18 penalize MDU Resources for organizational decisions which were made in
19 reliance on the past position of this Commission.
20 Montana-Dakota affiliates would need to consider alternatives to its
21 current corporate structure in order to avoid the future adverse
22 consequence of shifting of tax benefits derived from the activities of non-
23 regulated entities to ratepayers. A number of the entities which exist for

1 legitimate business or other legal reasons could very easily be merged.
2 Such consolidation would reduce the likelihood of net operating losses at
3 a single entity which can result from swings in local economic conditions.
4 However, such alternatives, while available presently to the affiliated
5 companies, would result in additional legal and filing costs that would
6 otherwise be unnecessary.
7 In addition, the current corporate structure for the affiliated
8 companies was determined giving consideration to best business
9 practices. Alternative structures could require changes that could result in
10 potential legal exposures or other business ramifications on a go forward
11 basis for the entire consolidated group, for the mere purpose of assuring
12 that the affiliated companies realize the tax benefits to which they are
13 entitled. A non-regulated affiliate should not be required to restructure and
14 assume additional legal risk merely to assure that the tax benefit of
15 potential net operating losses are not flowed through to the ratepayers of
16 an affiliated entity. This unfortunate result would be solely due to the
17 reallocation of tax savings in the manner proposed by Mr. Towers, which
18 violates the essential requirement to keep regulated and non-regulated
19 enterprises separate to the fullest practical extent.
20 Q. Do you believe another variation of the stand-alone method is
21 appropriate?
22 A. No other variation would result in as fair and equitable treatment for
23 all parties as the stand-alone method described and any such variations

1 would result in practical and fundamental problems. However, even if the
2 stand-alone methodology were not the accepted standard for rate
3 purposes, which we believe it is, any alternative for allocating the savings
4 of non-regulated affiliates should first consider whether the non-regulated
5 affiliates' combined taxable incomes and losses result in an overall
6 positive net income.
7 Q. Would you please explain why this methodology is more appropriate?
8 A. A fundamental ratemaking concept is the allocation of costs
9 between jurisdictional and non-jurisdictional operations. The taxable
10 income of the non-jurisdictional operations should be viewed in the
11 aggregate rather than on a company-by-company basis if one is proposing
12 to allocate income tax expense using a non-stand-alone methodology.
13 The regulatory agency should be indifferent to the results within the
14 operations at each of the respective non-jurisdictional entities. As a result,
15 it is the taxable income at each of the jurisdictional operations and the
16 aggregate amount of taxable income from the non-jurisdictional operations
17 that should be relevant for purposes of allocating the consolidated income
18 taxes. I would suggest that Mr. Towers, on page 2 of his Exhibit
19 No.___(RGT-2), by his distinguishing between the income for each
20 regulated entity and the total income of the non-regulated affiliates (as
21 compared to looking at each entity irrespective of whether regulated or
22 non-regulated), also gives some validity to this concept. One cannot
23 consider only the positive taxable incomes of the non-regulated entities,

1 but must consider all taxable income whether positive or negative in order
2 to determine whether there are any savings to be allocated. If the non-
3 regulated affiliates have sufficient income to offset losses at other non-
4 regulated affiliates, it should be clear that no savings are being realized as
5 a result of the non-regulated entities' participation in a consolidated return
6 and the regulated operations are not adding value to the losses of the
7 non-regulated affiliates.
8 Q. What amount of tax savings would be allocated to Montana-Dakota by
9 applying this alternative allocation approach which considers the total
10 income and losses of all non-regulated operations?
11 A. In our case, for each of the years considered by Mr. Towers, the
12 aggregate income of the non-regulated members of the consolidated
13 group (which would exclude Montana-Dakota and Williston Basin
14 Interstate Pipeline Company) was sufficient to absorb any losses which
15 were realized by the non-regulated entities for such years. Based on this
16 method of allocation there would be zero tax savings allocable to
17 Montana-Dakota as shown on Exhibit No. ___(AJF-2).
18 Q. Is the adjustment proposed by Mr. Towers consistent with a tax allowance
19 that reflects the recognition of expenses in the cost of service, which is
20 called "normalization," as compared to a tax allowance reflecting
21 recognition of the expenses on the tax return, which is called "flow-
22 through?"
23 A. The adjustment proposed by Mr. Towers is inconsistent with a

1 policy to follow normalization, which has been the general policy of this
2 Commission. The need for consistency between a normalization policy
3 and the method of allocating tax savings was addressed by the FERC on
4 pages 61,858 and 61,859 of Exhibit No.___(AJF-1). The FERC
5 determined that it was appropriate to follow a normalization policy rather
6 than a flow-through policy, because a flow-through policy mismatches
7 burdens and benefits. Under flow-through, ratepayers for earlier periods
8 receive the benefit for tax deductions which exceed the depreciation
9 expense being recovered currently, while ratepayers for later periods
10 receive the benefit for depreciation expenses being recovered which may
11 be greater than the tax deductions allowed for such periods.
12 The FERC concluded that under a normalization policy, the tax
13 benefits and expense burdens are being matched. The FERC determined
14 that once a normalization policy is adopted for dealing with tax and
15 ratemaking timing differences, it does not make sense to have a policy on
16 consolidated taxes that ignores the source of the loss.
17 The FERC illustrated this in a hypothetical situation involving
18 company H, which owns two subsidiaries: A, a gas pipeline, and B, an
19 electric utility. Company B puts into service a new generating unit, which
20 also yields a large amount of accelerated depreciation deductions. As a
21 result of these depreciation deductions, B realizes a net tax loss of $100,
22 while A has taxable income of $100. Companies A, B, and H file a
23 consolidated return. The consolidated income is zero, so there is no

1 consolidated tax liability. Because A would have had a $50 tax liability if
2 separate returns had been filed, the filing of a consolidated return
3 produces a tax savings of $50.
4 Following a normalization policy for establishing rates, B would
5 calculate its tax allowance on the assumption that tax deductions were
6 taken on the basis of straight-line depreciation and B would accumulate
7 deferred income taxes related to its excess tax depreciation deductions so
8 that they will be available to reduce its rate base now and its tax allowance
9 later.
10 The FERC indicated that a policy which would flow the consolidated
11 tax savings through to A's ratepayers was "simply wrong." The tax
12 savings produced by B's excess deductions belong to B's future
13 ratepayers, not A's current ratepayers. The FERC concluded "...it is B's
14 future ratepayers who will pay the expense associated with the
15 deductions....there should be no flow-through of the consolidated tax
16 savings to A's ratepayers." Thus, the FERC concluded that the rates
17 charged by a regulated entity should flow the tax benefits created by its
18 deductions through to the ratepayers who pay the associated expenses
19 when those expenses are recognized in rates. Timing differences reflected
20 on the group's consolidated return should be normalized in order to
21 eliminate the losses those differences create, irrespective of whether the
22 losses being reported by a company are subject to the FERC's rate
23 regulation.

1 Q. Does Mr. Towers' adjustment fully consider the impact of prior tax savings
2 generated within Montana-Dakota on a jurisdictional basis?
3 A. No, it does not. Montana-Dakota's federal income tax allowance
4 was computed on a stand-alone basis for Montana-Dakota's South Dakota
5 gas operations. In theory, one should apply Mr. Towers' theory by looking
6 at the taxable incomes for each of the separate regulatory jurisdictions in
7 which Montana-Dakota provides service. Assuming a situation somewhat
8 analogous to that of the hypothetical situation described in the FERC
9 order cited previously, one Montana-Dakota jurisdiction might have a tax
10 loss and another Montana-Dakota jurisdiction might have taxable income.
11 Following the principle that the tax allowance for each separate regulated
12 jurisdiction should be allocated on a stand-alone basis, the tax benefits
13 resulting from such a loss would be shared only with the ratepayers of the
14 jurisdiction incurring the expenses which resulted in the tax loss.
15 However, Mr. Towers proposes that the tax return entities with
16 income should realize the tax savings resulting from the losses of other
17 entities. Applying this same approach at only the Montana-Dakota level,
18 the tax allocable to Montana-Dakota would be allocated to each
19 jurisdiction based solely on those jurisdictions with positive taxable
20 income. Jurisdictions with tax losses would not receive the tax benefit
21 being derived from such losses. The tax savings generated in connection
22 with providing service to one group of ratepayers would be permanently
23 assigned to an entirely different group of ratepayers who did not pay for

1 the deductions resulting in the tax loss, who would realize this benefit
2 based solely on the fortuity of common ownership.
3 Q. Have there been instances where jurisdictional tax savings have been
4 created within Montana-Dakota?
5 A. Yes, there have been a number of such instances. In the late
6 1970's and early 1980's when several electric generating stations were
7 being constructed, Montana-Dakota reported significant tax savings
8 related to tax losses and/or investment tax credits within its electric
9 jurisdictions. In 1980, Montana-Dakota had an unconsolidated net
10 operating loss and in 1981 Montana-Dakota's loss resulted in a reportable
11 loss at the consolidated level. The tax savings related to these tax losses
12 were allocated to the customers of the jurisdictions who were paying the
13 expenses resulting in these losses. Applying the approach proposed by
14 Mr. Towers, the tax savings generated both at certain jurisdictional levels
15 and/or by Montana-Dakota as a whole would not be allocated only to the
16 customers of the jurisdictions who incurred the loss-related expenses, but
17 would also be allocated to the non-regulated affiliates.
18 For these same years and other years as well, there were
19 situations where a tax loss was realized within a particular jurisdiction
20 while another jurisdiction had realized taxable income for the same period.
21 By not using a stand-alone methodology for allocating tax expense at a
22 jurisdictional level, the concerns raised within the FERC analysis above
23 become a reality. Ratepayers in other jurisdictions would realize the tax

1 benefit of expenses which were paid for by a separate group of
2 ratepayers. The ratepayers who paid these expenses would be
3 permanently denied this related tax benefit while the ratepayers who did
4 not pay such expenses would have an unexpected windfall. This
5 illustrates why consistent use of the stand-alone method should be applied
6 for all periods in order to assure a fair allocation of tax expense to the
7 customers of each jurisdiction.
8 Q. Mr. Towers has proposed an adjustment to the federal income tax
9 allowance. Has he proposed a similar adjustment for a state income tax
10 allowance?
11 A. No, he did not. By failing to propose an adjustment for a state
12 income tax allowance similar to that proposed for purposes of determining
13 the federal income tax allowance, Mr. Towers appears to be proposing
14 that the stand-alone method should be applied for state income tax
15 allowance purposes, though Mr. Towers proposes that the stand-alone
16 method is not appropriate for determining the allowance for federal income
17 taxes. I believe this inconsistency is another flaw in his proposed
18 methodology.
19 Q. Would you please explain?
20 A. Applying a stand-alone methodology for the South Dakota gas
21 jurisdiction only, the state income tax allowance would be zero. However,
22 just as Montana-Dakota participates in the filing of a consolidated federal
23 return, it also is a participant in the filing of combined/consolidated state

1 income tax returns in a number of states. The taxable income related to
2 the earnings of the South Dakota gas jurisdiction are reported in these
3 state returns and apportioned based upon the relevant factors required by
4 the particular state. Therefore, following the theory that the liability
5 reported on the consolidated federal tax return should be shared with all
6 the profitable entities without regard to what the stand-alone liability would
7 be, a portion of the state tax for all the members of the
8 combined/consolidated tax filings should also be shared by all the entities
9 and a portion of such state taxes should be allocated to this jurisdiction.
10 Q. Are these combined/consolidated return filings limited only to those states
11 in which Montana-Dakota does business?
12 A. No, these filings include a number of states in which Montana-
13 Dakota does not do business. However, as the nature of a
14 combined/consolidated return takes into consideration all the unitary
15 entities, Montana-Dakota must be included in these filings as well. These
16 returns are similar to the federal consolidated return, where one filing is
17 made in the state for all the entities, irrespective of whether each of the
18 entities do business in that state. While this results in the creation of
19 additional state liability in these other states resulting from the earnings
20 generated by Montana-Dakota, there may also be a reduction in the state
21 tax liability for those states in which Montana-Dakota operates as a result
22 of the change in the apportionment factor to include the Montana-Dakota
23 affiliated companies. Therefore, if the stand-alone method is not applied,

1 a portion of the state tax liability for all states in which
2 combined/consolidated returns are filed needs to be allocated to this
3 jurisdiction.
4 Q. Have you calculated the amount of state income tax allowance that would
5 be necessary?
6 A. Yes, I have. The adjustment is an increase to the requested
7 allowance for current income taxes of $105,342 and is reflected in Exhibit
8 No.___(AJF-3).
9 Q. Does the allocation method proposed by Mr. Towers give you a concern in
10 the event that Montana-Dakota should have a federal or state tax
11 adjustment resulting from an examination?
12 A. Yes, it does. If a stand-alone method is applied, a subsequent
13 adjustment of the federal taxable income of a non-regulated entity should
14 generally have no impact on the tax allocated to Montana-Dakota. If the
15 allocation method proposed by Mr. Towers is applied, in the event of a
16 later adjustment, the consolidated tax and the respective amounts of
17 positive or negative income for the affiliates will need to be revised.
18 Montana-Dakota would be charged additional taxes related to these
19 adjustments. As interest could also be due with respect to such amounts
20 and the allocation of interest should follow the allocation of the underlying
21 tax, Montana-Dakota's ratepayers would now be expected to pay for taxes
22 and interest which might be solely related to changes in the taxable
23 income of the non-regulated entities.

1 Q. In Mr. Towers' testimony, he suggests that Montana-Dakota and its
2 customers could be encumbered with a tax liability in excess of that which
3 it would incur if Montana-Dakota were filing a separate return. Do you
4 agree?
5 A. As a member of a consolidated group, Montana-Dakota and each
6 of the other members which are part of the group for any part of the
7 consolidated return year are severally liable for the tax. However, I
8 believe that the shareholders of MDU Resources are ultimately at risk with
9 respect to the tax liability of other members of the group and I believe it is
10 highly unlikely that the ratepayers would ever be encumbered with this
11 liability. I do not believe that this Commission would approve the recovery
12 of taxes related to non-regulated entities from Montana-Dakota's
13 customers and I would agree with that determination. Therefore, I
14 disagree with the suggestion that the customers should share in the tax
15 savings related to the losses of affiliated companies as they share in the
16 potential for an increased tax liability. In fact, the opposite is being
17 proposed. Under Mr. Towers' proposal, the customers would share in the
18 tax savings of loss affiliates while likely not ever being exposed to the tax
19 liability directly related to the affiliates.
20 In addition, I would go one step further. I believe the affiliates with
21 tax losses, under Mr. Towers' allocation, would permanently lose any tax
22 benefits related to expenses which they have paid. Yet, these same
23 affiliates could be held severally liable for the tax obligations of Montana-

1 Dakota, which for such entities, would far exceed any benefit which they
2 might derive as a result of the filing of a consolidated return, even if these
3 affiliates were allocated the tax benefits of their respective losses. For this
4 reason and the other reasons stated previously, if the method proposed by
5 Mr. Towers is approved, these entities would need to reconsider whether
6 to continue to file future tax returns as part of a consolidated return, which
7 over the long-term could adversely impact Montana-Dakota.
8 Q. Do you believe the recognition of consolidated tax savings in utility rates
9 would violate the normalization requirements for accelerated depreciation
10 under the Internal Revenue Code?
11 A. I believe it may. Private Letter Ruling (PLR) 8643052, provided as
12 Exhibit No. ___(AJF-4) and PLR 8711050, provided as Exhibit
13 No.___(AJF-5), were issued addressing a fact pattern strikingly similar to
14 that of Montana-Dakota. In PLR 8711050, the National Office of the
15 Internal Revenue Service stated:
16 If Taxpayer were to introduce a variable, such as the tax
17 benefits resulting from the tax losses of affiliates, that served to
18 reduce the amount of federal income tax liability deferred under
19 section 1.167(1)-1(h)(1)(iii) of the regulations, Taxpayer would no
20 longer be regarded as using a normalization method of accounting.
21 Not only would the tax deferral, so reduced, be inadequate to meet
22 the normalization requirements, reduction would have the same
23 effect as the kind of adjustment to the reserve that is prohibited by

1 section 1.167(1)-1(h)(2). The consolidated tax savings adjustment
2 achieves through current tax expense a cost of service reduction
3 that would violate normalization requirements if achieved through a
4 reduction of deferred tax expense, and the effect is the same as if
5 there were a partial flow-through of the benefits of accelerated
6 depreciation as a result of deferring less than all the difference
7 between straight line and accelerated depreciation. The use of tax
8 benefits attributable to other entities in the determination of
9 deferred tax expense or current tax expense will cause Taxpayer to
10 fail to comply with the normalization provisions of section 167(1) of
11 the Code and the regulations thereunder.
12 The normalization requirements of section 168(e)(3) of the Code
13 are similar to the normalization requirements in section 167(l). If a
14 proposed method of accounting does not meet the normalization
15 requirements of section 167(1) it will not meet the requirements of
16 section 168(e)(3).
17 There is an additional reason why the consolidated tax
18 savings adjustment would violate the normalization provisions.
19 Sections 168(e)(3)(C) and 167(1)(3)(G) of the Code require
20 consistency with respect to the assumptions used for the
21 computation of tax expense, depreciation expense, deferred taxes
22 and rate base. The consolidated tax savings adjustment improperly
23 includes the transactions of all affiliates in determining ratemaking

1 tax expense without giving consideration to such transactions in
2 any other ratemaking calculations. That is to say, in developing tax
3 expense, Taxpayer's State Y Subsidiaries have not been viewed as
4 standing alone but as a part of the entire group, whereas for every
5 other ratemaking purpose these companies have been viewed as
6 stand alone. This lack of consistent assumptions violates sections
7 167(1) and 168(e)(3) of the Code.
8 Therefore, based on the above represented facts and our
9 legal analysis, we rule that:
10 Taxpayer's State Y Subsidiaries will not be in compliance
11 with the normalization requirements of sections 167(1) and
12 168(e)(3) of the Code if they use the consolidated tax savings
13 adjustment proposed by Commission that, for purposes of
14 determining cost of service tax expense, results in the current
15 element of tax expense being lower than current tax expense
16 computed at the statutory rate.
17 In PLR 8643052, based on similar legal analysis, the National Office ruled:
18 Taxpayer will not be in compliance with the normalization
19 requirements of sections 167(l) and 168(e)(3) of the Code, if, in
20 computing its total expense for purposes of establishing its cost of
21 service for ratemaking purposes, its current tax expense is reduced
22 by a portion of the tax savings attributable to the tax losses of Loss
23 Subsidiaries.

1 As our facts parallel those of these PLRs and based on the legal analysis
2 previously cited by the National Office, we believe the proposed
3 adjustment could result in a violation of the normalization requirements.
4 Q. Is this still the current position of the National Office?
5 A. We are uncertain of the answer to that question. The National
6 Office revoked both of these rulings in 1989, as a regulations project
7 addressing this subject was then in progress.
8 Q. Have regulations addressing this matter been promulgated?
9 A. On November 27, 1990, the Internal Revenue Service (the Service)
10 proposed regulations attempting to address the application of the
11 normalization rules with respect to consolidated tax savings. The
12 proposed regulations would have prohibited the current flow-through of
13 consolidated tax savings and essentially mandated a stand-alone method
14 of allocation for purposes of computing ratemaking tax expense. On
15 March 29, 1991, the Office of Management and Budget informed the
16 Treasury Department that any final regulations in this area would be
17 designated as a "major rule" under Executive order 12291. Due to the
18 extensive requirements of the "major rule" designation and the controversy
19 surrounding the regulations as proposed, the Service withdrew the
20 proposed regulations on April 25, 1991.
21 There were indications from the Chief Counsel at the Service in
22 September of 1991 that under the appropriate circumstances, the Service
23 may rule that such adjustments do not constitute a violation of the

1 normalization requirements. However, this individual and possibly others
2 who might have been associated with such indications are no longer with
3 the Service. Mr. Michael J. Graetz, then Deputy Assistant Secretary (Tax
4 Policy) for the Department of the Treasury, offered testimony concerning
5 this matter before the Subcommittee on Select Revenue Measures of the
6 Committee on Ways and Means of the United States House of
7 Representatives on September 11, 1991. Mr. Graetz stated that the
8 Internal Revenue Service and Treasury believed they had the legal
9 authority to issue the proposed regulations. Mr. Graetz described these
10 regulations in this manner: "These proposed regulations would have
11 prohibited current flowthrough of consolidated tax savings by denying a
12 utility the use of accelerated depreciation on its public utility property – the
13 only sanction permissible under the statute – unless the utility's tax
14 expense in determining its cost of service for ratemaking purposes is
15 determined on a stand-alone basis. Thus, the proposed regulations would
16 have prohibited regulatory commissions from taking consolidated tax
17 savings into account in computing ratemaking tax expense." Mr. Graetz
18 gave no indication that the position at Treasury had changed or that the
19 approach of the regulations would differ based on existing law.
20 Approximately twelve years have passed without clear direction
21 from the Service with regard to this issue and it is not known what the
22 position of the Service will be if this issue is raised at this time. Therefore,
23 we believe this is another consideration in support of continuing the

1 application of the stand-alone method for determining ratemaking tax
2 expense.
3 Q. Could you please summarize the amount of the adjustment to the
4 allowance for income taxes you believe appropriate?
5 A. For the numerous reasons above, I believe the correct income tax
6 allowance is that determined using a stand-alone method, which results in
7 no adjustment to the amount reflected in Montana-Dakota's filing. If the
8 stand-alone method is not accepted and Mr. Towers' proposal to share the
9 tax savings is approved, the determination of the amount of such savings
10 should be made based on the aggregate amount of taxable income and
11 losses for all non-regulated affiliates. Under such method, the federal
12 income tax allowance reflected in Montana-Dakota's filing would remain
13 unchanged and the total income tax allowance reflected in Montana-
14 Dakota's filing would be increased by $105,342 to reflect an increase for
15 the state income tax allowance.
16 Q. Does this conclude your rebuttal testimony?
17 A. Yes, it does.

Docket No. NG02-011
Exhibit No.__(AJF-1)

[¶ 61,396]

Columbia Gulf Transmission Company, Docket No. RP75-105-002; Columbia Gas Transmission Corporation, Docket No. RP75-106-006 (Consolidated Taxes)

Opinion No. 173; Opinion and Order Establishing Proper Cost of Service Treatment of Tax Liability Arising from the Filing of a Consolidated Tax Return

(Issued June 22, 1983)

Before Commissioners: C. M. Butler III, Chairman; Georgiana Sheldon and Oliver G. Richard III.

Appearances

John H. Pickering, Timothy N. Black, Andrea Timko Sallet, Richard T. Hiegel, Giles D. H. Snyder, Glen L. Kettering, and *James E. Coleman* for Columbia Gulf Transmission Company and Columbia Gas Transmission Corporation

Edward Berlin and *Andrew D. Weisman* for New England Power Company, Appalachian Power Company, Columbus and Southern Ohio Electric Company, Indiana & Michigan Electric Company, Kentucky Power Company, Kingsport Power Company, Michigan Power Company, Ohio Power Company, and Wheeling Electric Company

Richard Solomon, David D'Alessandro and *David E. Blabey* for the Public Service Commission of the State of New York

William T. Miller for the City of Charlottesville, Virginia

James T. McManus and *Dale A. Wright* for the Interstate Natural Gas Association of America

Hodges B. Childs and *James A. Biddison* for Baltimore Gas & Electric Company

Rose T. Lennon for Washington Gas Light Company

Frederick L. Jaffe, William A. Thielen, and *Demetrios G. Pulas* for the Staff of the Federal Energy Regulatory Commission

I.

Columbia Gas Transmission Corporation owns and operates an extensive pipeline system in the Appalachian and Atlantic coast regions. It sells natural gas at wholesale to a number of distribution systems. The company has much of its gas transported to it by Columbia Gulf Transmission Company, which owns and operates a pipeline extending from the Gulf Coast to Appalachia. In May 1975 each pipeline company tendered for filing increased rates. [1] As part of the justification for the increased rates, each pipeline included in its cost of service and allowance for federal income tax expense. Each pipeline determined its tax allowance as would any other company seeking an increase in rates from this Commission—by applying the applicable statutory tax rate to, essentially, the allowed return on equity. [2]

The City of Charlottesville, Virginia, a customer of Columbia Gas Transmission, contends that, because the pipelines are not like most other rate applicants, this method of determining the tax allowance produces excessive rates. Hence the question

Columbia group, including the pipelines, must be shared with, or flowed through, to the pipelines' ratepayers. This is so, Charlottesville argues, because the tax allowance for a utility is limited by established regulatory principle to the taxes it actually pays. According to Charlottesville, the pipelines' actual tax responsibility is a *pro rata* share of the consolidated tax liability. Since the consolidated tax liability reflects the tax reducing effects of using the excess deductions of the loss companies to reduce the taxable income of other members of the group, a tax allowance based on a *pro rata* share of the consolidated tax liability flows an equal share of the savings through to the pipelines' ratepayers. [6] Because the pipelines' tax allowances are greater than their *pro rata* share of the consolidated tax liability, Charlottesville argues that the tax allowances are excessive.

The Public Service Commission of the State of New York supports Charlottesville's position.

The pipelines, who are supported by our staff, a group of electric utilities, and the Interstate Natural Gas Association of America, take a different view. The pipelines concede that their tax allowances do not reflect any of the tax savings produced by the excess deductions of the four gas development companies. But they argue that, as a matter of proper ratemaking policy, those tax savings should not be reflected in the tax allowances. The pipelines contend that this is the correct policy because the ratepayers have not been charged with the responsibility of paying the expenses that gave rise to the excess deductions.

With respect to the parent, the pipelines and their supporters agree with Charlottesville that the savings produced by this company's excess deductions should be flowed through to the pipelines' ratepayers. This is so because the ratepayers have been charged with the responsibility of paying the expenses that gave rise to the parent's excess deductions. But it is the position of these parties that the method the pipelines used to calculate their tax allowances already reflects those savings. Hence, it is argued, no reduction in the tax allowances is justified.

IV.

There are thus two issues before us. One concerns the parent's loss. It is very technical—indeed, it is arithmetical. Does the pipelines' method of calculating their tax allowances flow the tax savings created by the parent's loss through to ratepayers?

The other issue concerns our policy towards utilities that join in filing a consolidated tax return. The precise question before us, though, is not so easily stated. The issue has had a long history at this Commission and at others. The terms of the debate—"actual taxes paid," "phantom taxes," "stand alone," "separate entity"—have acquired many meanings. Their use here suggests the division between the parties is stark and the question before us simple. Are the tax savings to be shared or are they not? Should the tax allowance be based on the consolidated return or should the filing of that return be ignored and the pipelines treated as though they filed separate returns?

These, however, are not the questions before us. The pipelines join in filing a consolidated tax return. And the Columbia group realizes a tax savings by filing such a return. There is no justification for ignoring that reality. And no one contends that we should.

The need for a different application of the principles stems from the fact that the income tax is not simply a tax on income. It is a tax on profits, which is gross income less the expenses incurred in producing income. So the tax allowance should be equal to the tax on the profit the ratepayers will contribute to the company. In short, the tax allowance should be equal to the tax on the company's allowed return on equity. [11] This is so because the allowed return on equity is the amount of profit the company should receive for providing service to the ratepayers.

There are, however, vast differences between our assessment of the profit the company is due and the calculation of the amount by which the company is considered to have been enriched by the Internal Revenue Service. Some of these differences stem from the differences in the revenue that is used in calculating the company's profit. The most obvious difference is that we base our determination of the company's profit on projections of revenue. The Internal Revenue Service uses, of course, the revenues the company either actually receives or accrues the right to receive during the tax year. There are even greater differences in the expenses that are recognized.

Because these differences are so vast, the Commission has found that the taxes the company pays to the Internal Revenue Service are not a reliable guide, even as a starting point, for determining a company's tax allowance. Instead, the Commission has always made its own assessment of the tax cost the company incurs in providing service.

We make that independent assessment by considering the two elements that go into the calculation of taxes—income and expenses—separately. We start by determining the income we expect the company to receive from the particular service in question. There is usually no problem with this. We then consider the deductions from income. This requires an allocation, for just as the expenses recorded in the company's books may be for services performed for different periods or different classes, so also with the deductions reported on the tax return. Here again we allocate on the basis of the customers' responsibility for the deductions.

Because deductions are given for expenses incurred in producing income, the necessary causal link between the ratepayers and the deductions is the expenses the company incurs in providing service. Accordingly, the proper way to allocate deductions is to match the deductions with the expenses included in the cost of service. Thus, when an expense is included in the cost of service, the corresponding tax deduction is also allocated to the ratepayers. In this way any tax reducing benefits, or savings, the company realizes in providing the service are recognized in calculating the tax allowance for the benefit of the ratepayers.

The corollary to this is that when an expense is not included in the cost of service (because the company did not incur that expense in providing service), the deduction created by that expense is not allocated to the ratepayers. To do otherwise would result in the tax savings the company realizes from expenses incurred in providing services to other groups and periods or for its own benefit being used to reduce rates for a particular group of ratepayers. The tax allowance would then be lower or higher than is warranted by the profit each group provides the company. Since the amount of profit to be provided is the measure of the tax cost the company will incur in providing service, none of the rates for the groups would be cost-justified. Subsidization would inevitably result. One group would bear the burden, but another group would gain the benefit.

return policy, our stand-alone policy in effect looks beneath the single consolidated tax liability and analyzes each of the deductions used to reduce the group's tax liability to determine the deductions for which each service is responsible. It then allocates to the jurisdictional service those deductions which were generated by expenses incurred in providing that service. In making this allocation it is irrelevant on which member's return the deductions would be reported if the group filed separate returns. Instead, the test is whether the expenses that generate the deduction are used to determine the jurisdictional service's rates. [17] Put more simply, the test is whether the expenses are included in the relevant cost of service. If they are, the associated deductions and their tax reducing benefits will be taken into account in calculating the tax allowance for that cost of service. If the expenses are not, the deductions will not be taken into account. In this way the tax allowance will reflect the profit the ratepayers contribute to the group's consolidated taxable income.

Application of our stand-alone policy to the facts of this case results in some of the tax reducing benefits the Columbia group realizes from filing a consolidated return being used to reduce the pipelines' tax allowances. Specifically, the benefits the group realizes from including the parent are used to reduce the pipelines' tax allowance; the tax benefits realized by including the four supply companies are not.

The parent reports a tax loss because its deduction for the interest expense it incurs in servicing its debt exceeds its income. [18] By filing a consolidated return this loss is used to reduce the taxable incomes of the pipelines and other members of the group. Hence the parent's interest expense creates a consolidated tax savings.

In setting the return for the pipelines we used the parent's interest expense as the pipelines' cost of debt. Thus, the ratepayers bear the burden of paying the parent's interest expense. That being so, an equal portion of the parent's interest expense deduction must be allocated to the pipelines' ratepayers. Our stand-alone policy does just this. [19] In this way it reflects in the tax allowances a portion of the consolidated tax savings created by the parent's loss. [20]

In 1974 the four supply companies were in various stages of starting their operations. So they had little or no revenue. [21] But because of certain provisions of the Internal Revenue Code they had large tax deductions. Hence each company contributed more deductions than income to the group's consolidated taxable income.

These companies have undertaken their projects to provide additional gas supplies for the system, including the pipelines. But the expenses these companies have incurred were not incurred in providing transmission service. So the requisite causal link between the pipelines' ratepayers and the expenses incurred is missing. The ratepayers were therefore not responsible for these expenses. Accordingly, none of the expenses of the gas development companies were included in the pipelines' cost of services. Because this is so, none of the deductions of the gas development companies should be allocated to the pipelines' ratepayers. And they are not under our stand-alone policy. To hold otherwise would result in tax allowances for the pipelines lower than are called for by the amount of profit the pipelines' ratepayers will contribute. The rates would then not be cost-justified or just and reasonable.

VII.

The method for determining the tax allowance Charlottesville advocates is considerably different. Charlottesville starts with each pipeline's *pro rata* share of the consolidated tax liability. Charlottesville calculates that amount by multiplying the

other businesses that have nothing to do with the gas business. Pipelines have becom involved in such businesses as real estate, financing, packaging, wire manufacturin textiles, shipbuilding, mining, and even vocational training and employmer services.[28]

That diversification causes problems for our regulation is obvious. It may expos the pipeline's ratepayers to a variety of burdens. The diversified activities may incu losses or costs that the company may attempt to pass on to the pipeline's ratepayer And the riskiness of the activities may impair the company's credit, thereby raisin the cost of capital. The universal response of regulators (at least at this Commission has been to try to isolate the ratepayers from these burdens. The Commission' allocation methods, which are designed to segregate the costs of jurisdictional and non jurisdictional businesses, solve many of the problems. But the Commission has gon beyond that to require that the costs of different jurisdictional services, such as ga production, be segregated from the costs of providing transmission service. [29] Th Commission has also attempted to limit the capitalization and cost of capital used i setting rates to the capitalization and cost associated with the pipeline business. [30] I short, the response has been to try to regulate the pipeline as an "independent entity' so that it is "considered as nearly as possible on its own merits and not on those of it affiliates." [31]

That too was the Commission's ultimate response to the consolidated tax problem But that took a while. There were several false starts.[32]

The first consolidated tax case dealing with a diversified company was *Olin Ga Transmission Company* in 1957. [33] Olin explored, produced, and transported gas. The group to which Olin belonged reported a tax loss on the consolidated return because the losses of Olin's parent on its independent gas exploration and development program exceeded the income from Olin and its other subsidiaries.

The Commission staff, following the established method, argued that because the group paid no taxes, no tax allowance should be included in Olin's cost of service. The judge and the Commission disagreed and allowed a tax allowance based on the company's return on equity. The Commission did so because the losses arose "from unregulated [*i.e.*, non-jurisdictional] business activities unrelated to Olin's natural gas operation." [34]

The Commission's holding seems sound in theory. As a panel of the Court of Appeals for the District of Columbia Circuit said in a famous *dictum*:

> [W]e are not aware of any principled basis for saying that natural gas consumers should pay less for gas simply because the unlikely hypothesis materializes and, say, Mobil Oil loses money in its Montgomery Ward investment. [35]

But as an administratively practical method, the Commission's holding leaves much to be desired. In many cases it would be easy to tell that the diversified activity is "unrelated" to the pipeline's gas operations. [36] But in other cases the task would not be so easy. The question of what makes an activity related can be answered in many ways. So there would be many questions and many close cases. [37]

These questions were never answered, however. The diversification movement was just beginning. So cases presenting the question were rare. And in the next case that did present the question the Commission changed policies again.

But beyond this, we cannot agree with this approach. The distinction between regulated and unregulated and the allocation method the Commission developed to reflect this distinction faces insurmountable problems.

Some of these problems are practical. The method is, or at least can be, difficult to apply.[45]

Other problems are more fundamental. One is that the distinction between regulated and unregulated is inconsistent with the principles this Commission uses to allocate costs. Instead, we allocate costs between jurisdictional and non-jurisdictional operations, and, where there are two or more jurisdictional operations, the costs incurred in providing the service whose rates are being determined and costs incurred in providing other services. The simple fact that a company's operations are regulated is quite irrelevant. So the *Cities Service* method does not conform to its own starting point.

Viewing the question more broadly we do not see why the absence of regulation makes a company's loss less significant to the task of determining a pipeline's tax costs. Adherence to that view could produce absurd results.[46]

A third problem concerns the loss of a regulated company. Under the *Cities Service* method such a loss is automatically used to reduce the taxable income of regulated companies.[47] Thus, the *Cities Service* method (or, for that matter, the method Charlottesville advocates) permanently assigns the tax savings generated in providing service to one group of ratepayers to an entirely different group of ratepayers, based solely on the fortuity of common ownership. We see no justification for that. If the tax savings are to be shared with any group of ratepayers, they should be shared with the ratepayers of the company that incurred the loss.[48]

Problems like these led the Commission to reassess the whole question and to start afresh in its *Florida Gas* decision.[49] This reassessment rested on two facts. One was that the complicated set of facts presented in the *Cities Service* case was not unique. Instead, as the Commission noted, "there has been an increasing tendency for pipeline affiliates to diversify and to engage in activities completely unrelated to gas pipeline operations or the gas business at all, so that determining a tax allowance for the pipelines' jurisdictional business on the basis of the activities of a far-flung conglomerate bears less and less relationship to the operations in which we are properly interested."[50] The second fact was that with other ratemaking questions the Commission had endeavored to isolate the pipeline business from the consequences of that diversification.[51]

In light of these facts the Commission concluded that a pipeline's tax allowance should not be based on the "activities of others in the affiliated group" but instead, like other costs, should be based on the activities of the pipeline itself.[52] Thus, the Commission rejected methods of determining the tax allowance by allocating a pro rata share of the consolidated tax liability and then adjusting that amount by excluding the losses of certain affiliates. In place of these methods the Commission installed the stand-alone method which determines the tax allowance on the basis of the pipeline's own revenue and expenses.[53]

We adhere to that judgement of the Commission. We do so for three reasons. First, the facts the Commission relied on have not changed. Pipelines are still diversified. We have no reason to believe that the diversity in the natural gas industry the Commission

new unit generates not only electricity but also a large amount of accelerated depreciation deductions, B's deductions exceed its income by $100. A, on the other hand, has taxable income of $100. A, B, and H file a consolidated return. The consolidated income is zero, so there is no consolidated tax liability. Because A would have had a $50 tax liability if separate returns had been filed, the filing of a consolidated return produces a tax savings of $50.

In setting rates for B we would, following our normalization policy, calculate B's tax allowance on the assumption that tax deductions were taken on the basis of straight-line depreciation. And we would require B to accumulate in a deferred account the tax reducing effects of its excess deductions so that they will be available to reduce its rate base now and its tax allowance later.

What then should we do in setting rates for A? According to Charlottesville, we should flow the consolidated tax savings through to A's ratepayers. This we think is simply wrong. The tax savings produced by B's excess deductions belong to B's future ratepayers, not A's current ratepayers. After all, it is B's future ratepayers who will pay the expense associated with the deductions. So here there should be no flow-through of the consolidated tax savings to A's ratepayers. [56] Hence to follow Charlottesville's method we would have to exclude B's losses from consideration.

Though this is a hypothetical, it is by no means atypical. This case presents several examples. During the test year Columbia LNG was building a terminal to receive and regasify imported liquefied natural gas. This portion of the company's business reported a tax loss because of typical timing difference expenses. That is, the company's construction expenses, such as interest during construction, were deducted for tax purposes. [57] But for ratemaking purposes these expenses were capitalized. The company will recover them over the life of plant through depreciation expense. Hence the deductions should be used to reduce the rates of that operation's future customers.

And that is what we did. When we set rates for this operation, we required that the tax reducing effects of the deductions for the construction period be accumulated in a deferred account so that they could be used to reduce the tax allowance over the life of the plant. [58]

The company also began to operate a synthetic natural gas plant in the test year. This operation also reported a tax loss solely because of timing difference expenses. [59] Though we have no jurisdiction over this operation and its rates, the company and customers have agreed to price the synthetic gas on a cost of service basis. So the company capitalized its construction expenditures, charged depreciation at a straight-line rate, and accumulated the tax effects related to those expenditures and its excess depreciation deductions in a deferred tax account. [60]

These results are proper. The rates Columbia LNG charges flow the tax benefits created by its deductions through to the ratepayers who pay the associated expenses when those expenses are recognized in rates. [61] Hence, if we were to follow Charlottesville's method, we would have to exclude from consideration Columbia LNG's losses. To do otherwise would result in the tax savings being flowed through twice. [62] There are many similar cases. [63]

This does not end the significance of normalization, however. Normalization is simply a method of allocating tax deductions over time. It tells us when a tax deduction should be recognized for ratemaking purposes. So before we could even apply Charlottesville's method, we would have to normalize the timing differences shown on

VIII.

Charlottesville and the Public Service Commission of the State of New York advance a number of arguments against our stand-alone policy. [71] Most of these arguments have been addressed previously. But two arguments warrant further comment.

A.

Both Charlottesville and the New York Public Service Commission contend that our stand-alone method is not supportable on the facts of this case. Though the parties express this contention somewhat differently, their point comes down to essentially this: "In instances where the jurisdictional ratepayers of a pipeline are fully insulated from the risks and increased costs associated with the investment activities of non-jurisdictional companies, . . . there may be some basis for reducing the ratepayers' share of the consolidated tax savings generated solely by such non-jurisdictional investments. The situation of the Columbia system, however, is not one of those instances." [72] That is so, the parties contend, because the activities of the pipelines' sister companies, especially the development companies, have imposed numerous burdens on the pipelines' ratepayers. Accordingly, the parties argue that in fairness the tax benefits created by the pipelines' sister companies ought to be shared with the ratepayers.

We disagree. To be sure, we agree with the principle that benefits should follow burdens. That is implicit in our stand-alone policy. What we disagree with is the parties' application of that principle. The task we have before us is to allocate the tax reducing benefits created by the system's deductions to the system's members. That must be done on the basis of some factor that is reasonably closely related to the benefits to be allocated. But the burdens Charlottesville and New York point to (to the extent they are burdens at all) are simply too far removed from the tax benefits to justify allocating the benefits to the ratepayers.

For example, it is argued that the ratepayers are burdened because the pipelines' internally generated funds are used to finance the system's gas supply efforts. Internally generated funds consist of net income (or profits), depreciation, and deferred income taxes. Since a pipeline would not have these funds but for the revenue provided by the ratepayers, the ratepayers can be said to be bearing a burden here. But this is not a burden imposed by the system's gas development activities. Pipelines are not eleemosynary institutions. Their shareholders are entitled to a return on, and a return of, their capital. Pipelines are also entitled to the use of the money ratepayers have paid for taxes that have not yet been paid to the government. The ratepayers have paid no more in rates because of the gas supply efforts. Moreover, what the pipelines' shareholders do with this cash is largely their own business. They may reinvest it in the pipelines or they may invest it in other business ventures. So we do not see how the particular investment decisions the pipelines' shareholders have made, namely, to invest a large part of the cash they derive from the pipelines in gas supply efforts, justify allocating any of the tax benefits created by those efforts to the ratepayers. [73]

We reach the same conclusion with respect to the argument that because the pipelines are "funneling" hypothetical taxes to the gas supply companies, the ratepayers have been burdened. [74] While the ratepayers are paying a tax allowance and are to that extent burdened, this is not a burden imposed by the gas supply companies. The tax allowances reflect the costs of providing service. Nothing has been

pipeline operations. This perception has entered into the market's calculation of Columbia's stock and would be reflected in a higher cost of equity. So the pipelines' rates of return reflect a "risk premium" for the system's exploration and development activities.[82]

The evidence shows that the system's exploration and development activities have had some impact on the cost of debt used in setting the pipelines' rates of return, though less than Charlottesville claims and far less than the tax benefits at issue.[83] This evidence might justify, on purely equitable grounds, some sharing of the consolidated tax savings if there were no other way to protect the ratepayers from this increased cost of capital.

But this is not the case.

Our stand-alone policy applies not only to the determination of a utility's tax allowance but also to the determination of the utility's rate of return.[84] Hence, when we use the parent's capital structure and costs, adjustments, where necessary, can be made to both elements to insure that the return reflects only the risks and costs of providing the specific service at issue. And where the question has been raised the Commission has done so. It has eliminated equity from the capital structure when the equity was used to finance non-utility business or operations that were separately regulated by the Commission;[85] it has eliminated the risks imposed on the system by operations other than the pipeline;[86] and it has endorsed in principle excluding from the rate of return the cost of debt that was not used to finance the pipeline business.[87]

So nothing prevented the parties from raising their concerns that the return was too high when that issue was presented to the Commission for decision. But they did not. Instead, they settled.[88] Hence what the parties' argument here amounts to is a plea that we use consolidated tax savings to relieve them of a bargain with which they are no longer happy. This we decline to do. The plea is too late.

B.

Charlottesville contends that our stand-alone method consistently produces tax allowances for the pipelines far larger than the pipelines' "actual tax responsibility." Charlottesville supports this argument with a table comparing the pipelines' stand-alone tax allowances with various amounts reported to the Internal Revenue Service on the group's consolidated returns.[89] This table shows, for example, that the rates in this docket, which were in effect for most of 1976, assumed that the pipelines' tax costs totalled $78.4 million. Charlottesville says that the pipelines' share of the group's actual tax liability was $60.6 million before investment tax credits and $52.8 million after investment tax credits. Moreover, Charlottesville says, in some years the pipelines' stand-alone tax allowances exceed the actual tax liability of the entire group. Charlottesville therefore argues that our stand-alone policy violates the statutory mandate that "requires that ratepayers reimburse a regulated pipeline only for actual costs, including federal income taxes" and is thus unlawful.[90]

We disagree. We do so not because we disagree with the principle that only actual costs should be included in the cost of service. Everything we have heretofore said in this Opinion shows that we are in complete agreement with that principle. Rather, we do so because we cannot agree that the amounts reported to the Internal Revenue Service represent the actual tax costs the pipelines incur in providing service.

considerably because of the way the members of the groups have chosen to adjust their earnings and profits. As a policy matter, we think that is unacceptable. The differences in rates would not be based on differences in the cost of providing service.[103] Accordingly, we see no alternative but to disregard the allocation the Columbia group uses for tax purposes and make our determination of the amount of the consolidated tax liability that should be allocated to the pipelines.

IX.

The other issue before us concerns the tax savings created by the parent's loss. This issue involves no question of policy. Everyone agrees that under our stand-alone method, these tax savings must be shared with the pipelines' ratepayers. Instead, the question here is the technical—though complicated—one of whether those savings have been used to reduce the pipelines' tax allowances.

These are the facts:

(1) The subsidiaries of the Columbia group issue no securities to the public. The parent secures all the capital for the system by issuing debt and equity securities to the public. The subsidiaries obtain their capital by issuing debt and equity to the parent.

(2) So the parent receives dividends and interest from its subsidiaries. And it pays interest to its bondholders.

(3) In calculating the consolidated taxable income on the consolidated return the parent's dividend income is excluded.[104] The parent therefore reports only its interest income and interest expense. Because the parent's interest expense is greater than its interest income, the parent reports a tax loss. This loss is used to reduce the taxable incomes of other members of the group. Thus, the parent's excess interest expense deductions create a tax savings.

(4) There are two reasons the parent's interest expense is greater than its interest income. One is that the interest rate on the bonds the parent issues to the public is slightly higher than the interest rate on the bonds the subsidiaries have issued to the parent. This difference in interest rates is minimal.[105] It accounts for only a small portion of the difference between the parent's interest expense and interest income.[106] The other reason for the difference is that the parent has more debt in its capital structure than do the subsidiaries. In 1974 the capital structures of the parent and the subsidiaries were as follows:[107]

	Parent	*All Subsidiaries*
Debt	57.8%	48%
Preferred Stock	2.1%	—
Common Equity	40.1%	52%
	100.0%	100%

(5) In settling most other issues in this case the parties agreed to use the parent's capital structure and cost of capital to establish the pipelines' rates of return. Thus, the rate of return is based on the parent's, not the pipelines', interest expense. Because this is so, our stand-alone policy requires that the tax savings created by the parent's excess interest deductions be used to reduce the pipelines' tax allowances.

by deducting the parent's interest expense against the pipelines' income. Since the consolidated tax liability reflects the tax savings, the tax allowance will, too.

This point can be demonstrated. Since the question is really one of arithmetic, we, like the parties, will do so by means of an example using simple numbers.

Suppose that P Company (P) sells $10,000 of securities to the public: $6,000 of bonds paying 10% and $4,000 of common stock on which P will pay 12%. P does not carry on any business. Instead, it forms a subsidiary, S Company (S), to transport natural gas. P invests all of its capital in S. For its $10,000 P receives $5,000 in bonds paying 8% and $5,000 of common stock on which S will pay 12%. S has no other capital. With its $10,000 S builds a pipeline.

Suppose further that at the beginning of the year S puts into effect rates that yield revenue of $1,560. At the end of the year S and P file a consolidated tax return. A customer then complains to the Federal Energy Regulatory Commission that S's rates are excessive.

To justify its rates S files a rate of return study and a cost of service. The rate of return study is based on P's capital structure and cost of capital. Those are as follows:

	Ratio	*Cost*	*Weighted Cost*
Debt	60%	10%	6.0%
Equity	40%	12%	4.8%
	100%		10.8%

Using this capitalization, S's cost of service study shows return, tax allowance, and revenue requirement as follows:

Debt		$ 600
Equity		480
Total Return		$1080
Less: Interest		(600)
Tax Base		$ 480
Tax Allowance (at 50%) [111]		$ 480
Revenue Requirement		$1560
Proof:		
Gross Income	$1560	
Less: Interest	(600)	
Taxable Income	$ 960	
Tax (at 50%)	$ 480	

The customer does not contend that using the parent's capital structure and cost of capital is wrong. What the customer argues is that the tax allowance is too high. This is so, the customer argues, because the tax savings produced by filing a consolidated return are not reflected in the rates. To do that an effective tax rate must be used. S takes the opposite position. It argues that the tax allowance already reflects the tax savings.

If S is correct, the tax allowance should be equal to the consolidated tax liability. That is in fact the case.

	P's Interest/ Statutory Rate	S's Interest/ Effective Rate	P's Interest/ Effective Rate
Debt	$ 600	$ 600	$ 600
Equity	480	480	480
Return	$1080	$1080	$1080
Less: Interest	(600)	(400)	(600)
Tax Base	$ 480	$ 680	$ 480
Tax Allowance	$ 480 [116]	$ 480 [117]	$ 339 [118]
Revenue Requirement	$1560	$1560	$1419

Charlottesville thinks all this is irrelevant. According to Charlottesville, what is significant is that the parent's cost of debt is higher than the costs the pipelines incur on the debt they have issued to the parent. Since the parent's cost of debt was used in setting the rate of return for the pipelines, Charlottesville argues that the ratepayers are reimbursing the pipelines for costs not incurred.

It is difficult to know what to make of this argument. It sounds as though Charlottesville's complaint is with the use of the parent's cost of debt in setting the rate of return rather than with the use of the parent's interest expense as a deduction in calculating the tax allowance. But Charlottesville says that this is not its position. Charlottesville recognizes that in settling other parts of the case it has agreed to use the parent's capital structure and costs for the pipelines' return. Charlottesville says that it is not contending that the settlement's rate of return should be changed.[119] Instead, Charlottesville says that its position is that, because the return is inflated, deducting the parent's interest expense does not flow the tax savings through.

This argument is without merit. The issue here is whether the tax savings created by the parent's interest expense have been flowed through by deducting those expenses in calculating the pipelines' tax allowances. To answer that we must look at the tax consequences of our order. Those consequences are unaffected by the interest expense we use in setting the return. Companies do not report income on the basis of what revenues recover their equity return and what recovers their debt costs. Instead, they simply report gross income and deductions. So whether the pipelines' or the parent's cost of debt is used in the setting, the return tells us nothing about the tax consequences. That must be determined by considering the interest expense deductions taken on the consolidated return. [120]

What this argument does tell us, then, is that despite its statements to the contrary, Charlottesville's position is that using the parent's capital structure and costs has inflated the return. Is this so? Nothing in the record shows that a return based on the pipelines' own capital structure and costs would be lower. [121] But even if there were, we could not conclude that the return is inflated. As we have said previously, where a subsidiary issues no securities to the public, its capital structure and costs should not be used. [122] Those elements have been determined by the parent, not the market. The parent can manipulate those elements for its own advantage. That cannot be permitted. Moreover, in this case the parties, including Charlottesville, have agreed to use the parent's capital structure and costs. That agreement is final. So it is too late to complain now that the return is too high.

used in preparing the consolidated return "differs sharply from the separate taxable income of the members that would be reported on separate returns." Peel, *A Treatise on the Law of Consolidated Federal Income Tax Returns* § 5.03 (2d ed. 1973). *See also supra* p. 2. Even if these differences were ignored, there would be other problems. Many deductions permitted by the Code are elective. For example, certain interest during construction and intangible drilling costs may be deducted when incurred or capitalized and depreciated later. Hence a separate return policy requires an assumption about the deductions the jurisdictional service would report if it filed a separate return. Presumably, the assumption would be that the jurisdictional service would report deductions in exactly the same manner as the group does on the consolidated return. Whether the service would do so if it in fact filed a separate return is open to question. *See* Exh. 5 at 12; Tr. 247, 425.

[17] *Louisiana Power & Light Company*, Opinion No. 110, 14 FERC ¶ 61,075, at p. 61,124 (1981) ("The test [for determining when the consolidated tax savings should be flowed through to the jurisdictional customers] is whether the expenses which created the deductions used to achieve the tax savings were paid by the jurisdictional customers."); *Southern California Edison Company*, Opinion No. 821, 59 FPC 2167, 2174 (1977).

[18] The parent also incurs some expenses in serving stockholder accounts and paying its directors. These expenses are deductible. But there is no issue here that these deductions should be used to reduce the pipelines' tax allowances.

[19] We will explain in more detail how this is done. *See infra* pp. 50-57.

[20] Under a separate return policy the result would be different. The tax allowance for the pipelines would be calculated by using the pipelines' lower interest expense deductions because those are the deductions the pipelines would report if they filed separate returns. Under a separate return policy none of the tax reducing benefits the Columbia group realizes by offsetting the parent's loss against the income of the group would be reflected in the pipelines' rates.

[21] Columbia LNG began operating a plant for the manufacture of synthetic gas in 1974. The company was also constructing a plant to store and regasify imported liquefied natural gas. Columbia Coal was engaged in the development of methods of converting coal to gas. But it did not produce any gas. Nor did it produce any revenue. Columbia Gas Development of Canada was exploring for gas in Canada and the Arctic. Like Columbia Coal, this company produced neither gas nor revenue. Columbia Gas Development was exploring for gas in the Southwest. This company also produced some gas. So this company produced some revenue, but not enough to offset its deductions.

[22] See Exh. 22B for the calculations.

Charlottesville suggested an alternative method that reaches the same result. Under this method the total losses of the group are multiplied by each pipeline's allocation ratio. The pipeline's share of the losses are then taken as an additional deduction in calculating the pipeline's tax base for the cost of service. The statutory rate is applied to the tax base so calculated. *See* Exh. 23B.

[23] *Michigan-Wisconsin Pipeline Company*, Opinion No. 275, 13 FPC 326, 373 (1954); *Ohio Fuel Gas Company*, 13 FPC 281, 286 (1954); *Home Gas Company*, Opinion No. 272, 13 FPC 241, 246 (1954); *Hope Natural Gas Company*, Opinion No. 262, 12 FPC 342, 347 (1953); *United Fuel Gas Company*, Opinion No. 258, 12 FPC 251, 264-65 (1953); *Atlantic Seaboard Corporation*, Initial Decision, 11 FPC 486, 515, *aff'd*, Opinion No. 225, 11 FPC 43 (1952); *Hope Natural Gas Company*, Initial Decision, 10 FPC 583, 612 (1950), *aff'd*, 10 FPC 625 (1951); *Penn-York Natural Gas Corporation*, 5 FPC 33, 38-39 (1946).

[24] This fact does not appear in the Opinions. But the records establish that in all but one instance the parent was the primary, if not only, reason the group realized a tax savings by filing a consolidated tax savings. The one exception was the first consolidated tax case, *Penn-York Natural Gas*. The record in that case does not reveal the source of the tax savings.

In three cases, *United Fuel Gas*, *Ohio Fuel Gas*, and *Home Gas*, which all involved the Columbia group for the same time period, some of the tax savings were created by losses incurred by the pipelines' retail distribution affiliates. The Commission flowed those savings through to ratepayers. Since the amounts at issue were very small, we can appreciate why the Commission made no distinction between these tax savings and the much larger tax savings created by the parent's loss. Nevertheless, we have our doubts about this aspect of the Commission's decisions. *See infra* p. 26.

[25] Rates are now determined somewhat differently. Hence a different method must be used to reach the same result. *See infra* p. 57 and note 115.

[26] *Michigan Wisconsin Pipeline Company*, 13 FPC at 373; *Home Gas Company*, 13 FPC at 246.

This same reasoning was followed by the Commission in Opinion No. 47 with respect to the loss of Columbia's retail distribution subsidiary in West Virginia. That company lost money from 1970 through 1974 because the state public utility commission had imposed a rate moratorium. The moratorium was lifted late in 1974 so the company was expected to have in place rates that would enable it to report taxable income in the future. Because of that, the Commission held that this loss should be ignored in calculating the tax allowances for the pipelines. 8 FERC at p. 61,009. The Court of Appeals affirmed. 661 F.2d at 952.

(We note that this rationale would be equally applicable to the loss of Columbia LNG. Although this company reported a tax loss in 1974, the test year, the company has since reported taxable income in every year but one. *See* Exh. 2, Schedule 3; Exh. 5 at 12-13; Exh. 14, Schedule 16.)

[27] This is, however, an area we would prefer to avoid. Many of the instances where there is an allegedly non-recurring loss have involved and will involve a retail subsidiary that has a tax loss. Since we do not regulate retail subsidiaries, it is very hard for us to form a reliable judgment, absent special circumstances as were present in the case of Columbia's West Virginia retail subsidiary, about when these companies will report taxable income.

the pipelines. That seems to us to be a little bit wasteful of the Commission's resources.

[46] Hypotheticals are easy enough to think of. For example, in the Columbia system the operations of the parent, Columbia Coal Gasification, the synthetic gas operations of Columbia LNG, and (probably) Columbia Gas Development of Canada are unregulated. Suppose that in the future the unregulated operating subsidiaries made bundles of money and had more than enough taxable income to absorb the parent's loss. Under the *Cities Service* method the tax savings produced by the parent's loss would not be used to reduce the pipelines' tax allowances. But these tax savings should be shared with the pipelines' ratepayers.

[47] In *Cities Service* the regulated company with the loss was a company that transported oil by pipeline. The company was then regulated by the Interstate Commerce Commission.

[48] The point can be put a little more bluntly. The method may look fair to ratepayers of a company with taxable income. But we doubt it looks fair to the ratepayers of the company with a loss.

[49] 47 FPC at 362-63, *supra* p. 10. The Commission noted the problem of using the tax loss of one regulated company to reduce the tax allowance of another regulated company.

[50] *Id.* at 362.

[51] *Id.* The Commission cited its decision in *El Paso Natural Gas Company*, 44 FPC at 77, *supra* note 30, to exclude the company's investment in its manufacturing affiliate from the pipeline's capitalization.

[52] *Id.* at 363.

[53] In *dicta* the Commission also expressed its view that a change to the stand-alone method was needed to avoid "discouraging" gas exploration. *Id.* at 362. In Opinion No. 47 the Commission applied the stand-alone method in this case largely for this reason.

We, however, do not rely on this rationale. *See supra* note 8.

[54] The Commission decided *Florida Gas* at the height of the trend towards diversification. In 1972 pipeline operations of the companies in Moody's Natural Gas Transmission Index contributed only 54% of the companies' gross revenues. Since then, pipeline operations have contributed about the same percentages of their companies' gross revenues. *See supra* note 28.

[55] Charlottesville moves that all evidence concerning normalization be struck from the record. Charlottesville contends that any consideration of the impact the Commission's normalization policy may have on the proper policy to follow with respect to consolidated taxes is beyond the scope of the Court's mandate remanding this case to us. We disagree. We do not think we are so constrained. *See S.E.C. v. Chenery Corp.*, 332 U.S. 194, (1947). Accordingly, the motion is denied.

[56] Note that since the hypothetical concerns 1982, B's depreciation expense deduction for tax purposes would be governed by the new Accelerated Cost Recovery System, which was enacted by Congress in the Economic Recovery Tax Act of 1981 Pub. L. No. 97-34, § § 201-209, 95 Stat. (1981). If th utility is to use that method, its rates must be set o a normalized basis. Having done that for B, question has been raised whether flowing the saving through to A's ratepayers would violate the statutor mandate. *See* Exh. 1 at 5; Exh. 11 at 21. For contrary view, see Exh. 13 at 54-55; Tr. 534.

Without a definitive ruling from the Interna Revenue Service, we cannot resolve this question.

[57] Exh. 3. These timing difference expenses wer the only source of the loss. Thus, if this operation' expenses were reported on the tax return in the same way that we recognized expenses in the cost o service, the LNG operation would not have reporte a tax loss.

[58] *See Columbia Gas Transmission Corporation*, 8 FERC ¶ 62,005 (1979).

[59] Exh. 3.

[60] Exh. 1 at 5-6.

[61] It might be argued that whatever the merits of normalization in other cases, it is irrelevant here. This is so, it might be argued, because the ratepayers of Columbia LNG are the ratepayers of the pipeline. Since that is so, normalization is not needed to preserve the tax benefits for ratepayers. The tax benefits should therefore be flowed through to the pipelines' ratepayers immediately.

We reject this argument. Columbia LNG's rates are normalized. It would be extremely hard to undo that now.

But even if those decisions had not already been made, we would reject this argument. The liquefied natural gas the company produces is sold to Columbia Gas Transmission and flows to all the ratepayers of the pipeline. But still the ratepayers are not identical. The ratepayers who should receive the tax benefits are those customers who will pay the expenses over the life of the plant. But under Charlotteville's method the ratepayers who receive the benefits are the ratepayers of 1976. Those two groups of ratepayers can never be exactly the same. So Charlottesville's method would create an intergenerational subsidy.

The situation is slightly different with respect to the synthetic gas this company produces. This gas is sold directly to customers of Columbia Gas Transmission. The pipeline performs only a transmission function. Tr. 390. Not all of the pipeline's customers decided to purchase synthetic gas. Exh. 15 at 18. So Charlottesville's method would not only create an intergenerational subsidy here but would also result in the synthetic gas customers subsidizing the pipeline's customers who did not purchase synthetic gas.

[62] Conceivably, we could flow the tax savings created by Columbia LNG's deductions through to the pipeline's ratepayers and still normalize Columbia LNG's rates. To do this, however, we would need to establish a mechanism whereby the pipelines would repay Columbia LNG for the use of its losses as the expenses are recognized in Columbia LNG's rates. This we decline to do. Setting up the required accounting would be complicated. And doing so would cause the pipelines' rates to fluctuate on the basis of

[77] *Kentucky West Virginia Gas Company*, Opinion No. 7, 2 FERC ¶ 61,139, at p. 61,326, *reh. denied*, 3 FERC ¶ 61,225 (1978).

[78] *Id.*

[79] *Manufacturers Light and Heat Company*, Opinion No. 583, 44 FPC 314, 326, *reh. denied*, 44 FPC 1138 (1970); *Manufacturers Light and Heat Company*, 23 FPC 446, 448 (1960).

Charlottesville's witness thought this was preferable to using hypotheticals. Exh. 13 at 21.

[80] *See Kentucky West Virginia Gas Company*, 2 FERC at p. 61,326.

[81] Exh. 13 at 22-24.

[82] *Id.* at 21-22.

[83] Charlottesville says that the cost of debt was raised from 6.60% to 7.29% and that the pipelines' revenue requirement was increased by $5.2 million. Exh. 13 at 23-24; Exh. 14, Schedules 4-8.

Columbia does not dispute that the pipelines' revenue requirements have been increased. But it argues that the increase is only $2.6 million. Exh. 15 at 8-10; Exh. 16. We think Columbia is correct.

We find no evidence that the system's gas supply efforts have caused investors to add a risk premium to Columbia's stock. While it is no doubt true that investors view gas exploration activities as riskier than the pipeline business, that is not enough to establish the existence of a risk premium. An investor's required return is based on the consolidated earnings power of the Columbia system. That system is large and operates in all the major areas of the gas business. Hence before we could conclude that the system's gas supply activities have raised the investor's required return, we would need evidence on the system's other business activities and how those activities interact with the gas supply efforts. But no such evidence was offered. Moreover, the only evidence in the record that remotely bears on this question is the credit rating for the system. Throughout the 1970's Columbia maintained an A credit rating. Exh. 15 at 7. This suggests to us that investors' perceptions of the riskiness of the system were not greatly affected by the existence of the gas supply companies.

[84] *Kentucky West Virginia Gas Company*, 2 FERC at p. 61,325.

[85] *El Paso Natural Gas Company*, 44 FPC at 77; *Southern Natural Gas Company*, Opinion No. 585, 44 FPC 567, 571-73 (1970).

[86] *See e.g.*, *Arkansas Louisiana Gas Company*, Opinion No. 71, 10 FERC ¶ 61,027, at p. 61,046, 10 FERC ¶ 62,195 (1979), *rev'd on other grounds*, 654 F.2d 435 (5th Cir. 1981); *Consolidated Gas Supply Corporation*, Opinion No. 70, 10 FERC ¶ 61,029, at p. 61,053 *reh. denied*, 10 FERC ¶ 62,224 (1979), *aff'd* 653 F.2d 129 (4th Cir. 1981); *Natural Fuel Gas Supply Corporation*, Initial Decision, 5 FERC ¶ 63,018, at pp. 65,143-45 (1978), *aff'd*, Opinion No. 58, 8 FERC ¶ 61,135 (1979); *Pacific Gas Transmission Company*, 43 FPC at 842-43.

[87] *Florida Gas Transmission Company*, Opinion No. 561, 42 FPC 74, 79, *reh. denied*, 42 FPC 649 (1969), *rev'd on other grounds sub nom. Sun Oil Co. v. F.P.C.*, 445 F.2d 764 (D.C. Cir. 1971) (cost of debt should in theory be lowered, but no adjustment mad because the difference was trivial).

[88] *See* the order issued in these dockets o September 13, 1976. 56 FPC 1651.

[89] *See* Table II on page 28 of Charlottesville Initial Brief.

[90] Initial Brief for Charlottesville at 31.

[91] The basic differences are described in th pipelines' Reply Brief at 4, 9-10.

[92] *See supra* p. 15.

[93] I.R.C. § 1552(a); 26 C.F.R. § § 1.1502-33(d and 1.1552-1(a).

[94] I.R.C. § 1552(a)(1); 26 C.F.R. § 1.1552 1(a)(1)(ii).

[95] Tr. 165.

[96] I.R.C. § 1552(a); 26 C.F.R. § § 1.1502-33(d and 1.1552-1(a).

[97] I.R.C. § 316(a).

[98] That is determined either by an agreement among the members of the group or, where the group is a public utility holding company like Columbia, by the rules and orders of the Securities and Exchange Commission. *See supra* n. 74.

[99] *See* Technical Information Release 878, 1967 Stand. Fed. Tax Rep., ¶ 6396, where it is said:

> The alternative methods of allocating the Federal income tax liability provided under section 1552 of the Code, as well as the methods provided under the proposed regulations [codified at 26 C.F.R. § 1.1502-33] may be elected even though the Federal income tax liability may be allocated in a different manner for purposes other than the Internal Revenue Code, which are not intended to be affected.

[100] *See* I.R.C. § 1552(a)(2)-(4) and 26 C.F.R. § § 1.1502-33(d)(2)(i)-(iii) and 1.1552-1(a)(2)-(4).

[101] *See* 26 C.F.R. § 1.1502-33(d)(2)(ii).

[102] *See* 26 C.F.R. § § 1.1552-1(c)(1) and 1.1502-33(d)(3).

[103] For example, the Southern Natural Gas Company has, since 1967, joined with its parent, Sonat Inc., and its affiliates in filing a consolidated tax return. For tax purposes the Sonat group allocates its consolidated tax liability in a way that the members' reporting a tax loss are credited with the "tax savings"—just the opposite of the method the Columbia group uses. *See* Exh. 1(j) at 4, *Southern Natural Gas Company*, Opinion No. 174, 23 FERC ¶ 61,397. Thus, if we were to follow the allocation method the group uses for tax purposes, the ratepayers of the Columbia pipelines would receive the tax saving the group derives from filing a consolidated return but the ratepayers of the Southern pipeline would not. We can perceive no justification for that.

[104] 26 C.F.R. § 1.1502-14(a).

[105] What happens is this: The parent will, for example, issue 30 year bonds to the public paying a coupon rate of 9.83%. When the parent lends money to one of its subsidiaries, the maturity and interest rates on the subsidiary's bonds are tied to those of the

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Consolidated Federal Income Tax Savings

	(A)	(B)	(C)	(D)	(E)
1	1999-2001 average taxable losses used to reduce the consolidated taxable income of MDU Resources Group, Inc.	$0			
2	Allocated to Montana-Dakota Utilities Co.	$0			
3	Consolidated tax savings @35%	$0			
			Taxable Income Y.E. 6/30/02		Consolidated Tax
			Amount	Ratio	Savings
	Allocation to operations:				
4	Gas utility		$8,609,271	0.201393	$0
5	Electric utility		33,283,997	0.778597	0
6	Non-utility		855,421	0.020010	0
7	Total		$42,748,689	1.000000	$0
	Allocation to Gas utility - South Dakota				
8	Total Gas utility		$8,609,271	1.000000	
9	South Dakota		$2,160,760	0.250981	$0

Sources:
Column B: Lines 1-2 - Page 2
Column C: Statement K, pages 1 and 4

Allocation of Taxable Losses Used to Reduce Consolidated Tax Liability of MDU Resources Group

Participating Companies	1999 Number	1999 Taxable Income(Loss)	2000 Number	2000 Taxable Income(Loss)	2001 Number	2001 Taxable Income(Loss)	Averages	Ratios	Allocation of Avg.Taxable Losses
Companies with taxable income									
Rate-regulated									
Montana-Dakota Utilities	1	$36,893,019	1	$35,915,090	1	$48,062,511	$40,290,207	0.366310	$0
Williston Basin Interstate	1	11,007,753	1	13,348,491	1	29,137,835	17,831,360	0.162119	0
Unregulated companies	41	36,413,289	50	19,560,498	57	99,629,382	51,867,723	0.471571	0
Total w/taxable income	43	$84,314,061	52	$68,824,079	59	$176,829,728	$109,989,289	1.000000	$0
Consolidated	43	$84,314,061	52	$68,824,079	59	$176,829,728	$109,989,289		

Sources: Response to Staff Data Request No. 18
Statement K, Schedule K-3

MONTANA-DAKOTA UTILITIES CO.
Gas Utility - South Dakota
Consolidated State Income Taxes

	(A)	(B)	(C)	(D)	(E)
1	1999-2001 average state income taxes related to the consolidated taxable income of MDU Resources Group, Inc. -	$5,689,425			
2	Allocated to Montana-Dakota Utilities Co.	$2,084,095			

		Taxable Income Y.E. 6/30/02		Consolidated State Income
		Amount	Ratio	Taxes
	Allocation to operations:			
3	Gas utility	$8,609,271	0.201393	$419,721
4	Electric utility	33,283,997	0.778597	1,622,670
5	Non-utility	855,421	0.020010	41,704
6	Total	$42,748,689	1.000000	$2,084,095
	Allocation to Gas utility - South Dakota			
7	Total Gas utility	$8,609,271	1.000000	
8	South Dakota	$2,160,760	0.250981	$105,342

Sources:
Column B: Lines 1-2 - Page 2
Column C: Statement K, pages 1 and 4

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Allocation of State Income Taxes Related to the Consolidated Tax Liability of MDU Resources Group

Participating Companies	1999 Number	1999 Taxable Income(Loss)	2000 Number	2000 Taxable Income(Loss)	2001 Number	2001 Taxable Income(Loss)	Averages	Ratios	Allocation of Average State Income Taxes
Companies with taxable income									
Rate-regulated									
Montana-Dakota Utilities	1	$36,893,019	1	$35,915,090	1	$48,062,511	$40,290,207	0.366310	$2,084,095
Williston Basin Interstate	1	11,007,753	1	13,348,491	1	29,137,835	17,831,360	0.162119	922,364
Unregulated companies	41	36,413,289	50	19,560,498	57	99,629,382	51,867,723	0.471571	2,682,966
Total w/taxable income	43	$84,314,061	52	$68,824,079	59	$176,829,728	$109,989,289	1.000000	$5,689,425
Consolidated	43	$84,314,061	52	$68,824,079	59	$176,829,728	$109,989,289		
Consolidated/Combined State Income Ta		$4,839,233		$3,422,103		$8,806,938	$5,689,425		

Sources: Response to Staff Data Request No. 18
Statement K, Schedule K-3

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MDU Resources Group, Inc. and Affiliated Companies
Consolidated/Combined State Income Taxes

DESCRIPTION	2001 Cons/Comb	2000 Cons/Comb	1999 Cons/Comb
TOTAL STATE INCOME TAX PROVISION			
States Filing Combined:			
North Dakota	$2,091,181	$945,044	$1,404,446
Montana	1,786,761	561,784	942,566
Alaska	335,803	142,401	199,161
California	1,421,970	785,538	989,154
Oregon	1,920,949	805,825	1,103,682
Arizona	5,738	255	0
Colorado	50,564	9,860	1,125
Kansas	180,145	7,287	544
Minnesota	1,119,003	75,914	514
Nebraska	11,068	671	0
Utah	8,210	4,697	400
Illinois	326	36	0
Idaho	1,420	7,779	1,534
Hawaii	(126,201)	75,012	196,107
Combined Liability	$8,806,938	$3,422,103	$4,839,233

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LTR 8643052

Section 167 -- Depreciation Deduction

Index Nos.: 0167.23-00, 0168.00-00

Summary

PROPOSED TREATMENT OF SUBSIDIARY LOSSES WOULD VIOLATE NORMALIZATION REQUIREMENTS.

A regulated public utility is subject to the rate making jurisdiction of a public commission. As part of the utility's rate case before the commission, a financial consultant urged the commission to adopt a method of computing tax expense for purposes of computing cost of service where the utility reduces current tax expense by the tax savings attributable to a portion of the tax losses realized by its subsidiaries. A portion of those losses would be allocated to the utility and the resulting tax savings would reduce the utility's current tax expense.

The Service has ruled that adoption of the method suggested by the consultant will leave the utility out of compliance with the normalization requirements of sections 167(l) and 168(e)(3), if the utility reduces its current tax expense by a portion of the losses attributable to its subsidiaries. The Service noted that the consultant's proposed method would leave tax deferral inadequate to reduce normalization requirements and would have the same effect as the kind of adjustment to the reserve that is prohibited by regulation section 1.167(l)-1(h)(2).

The Service added that section 168(e)(3)(C) requires consistency with respect to the assumptions used for computing tax expense, depreciation expenses, deferred taxes, and rate base. Under the proposed method, the subsidiaries' losses are ignored for purposes of determining the firm's rate base and depreciation expense, but used for purposes of determining the firm's regulated tax expense.

Full Text

Refer Reply to: CC:C:E:1:2

July 29, 1986
In re: Private Letter Ruling Request * * *
LEGEND:
Taxpayer or Company = * * *
Regulatory Commission or Commission = * * *
State Y = * * *
R = * * *
S = * * *
T = * * *

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W = * * *
Rate case = * * *
Loss Subsidiaries = * * *
Dear * * *

We received your request for a private letter ruling dated September 30, 1985, and subsequently filed data, as prepared by your authorized representative. Your request generally pertains to the normalization provisions of section 167(l) and 168(e)(3) of the Internal Revenue Code. Specifically you have requested the following ruling:

Whether Company will be in compliance with the normalization requirements of sections 167(1) and 168(e)(3) of the Code if, in computing its total tax expense for purposes of establishing its cost of service for ratemaking purposes, Company's current tax expense is reduced by the tax savings attributable to the tax losses of Loss Subsidiaries.

You have made the following representations:

Taxpayer is a regulated public utility engaged in the production, transmission and distribution of electricity wholly within State Y. Company is subject to the jurisdiction of Commission with respect to rates, service, accounting and other matters. In * * *, Taxpayer acquired the assets of W. As a result, since that time Taxpayer has also been engaged in the distribution of natural gas.

For the years * * * through * * * Company filed its federal income tax returns as a member of an affiliated group filing on a consolidated basis of which it was the parent company. With the exception of R, none of the other members of the affiliated group are regulated public utilities. However, S is a utility service corporation, and T sells a small portion of its coal to Taxpayer.

As part of the Taxpayer's rate case before the Commission, a financial consultant offered his opinion on this normalization issue. He urged the Commission to adopt a method of computing tax expense, for determining cost of service, wherein Company reduces its current tax expense by the tax savings attributable to a portion of the tax losses realized by its Loss Subsidiaries. Under the methodology proposed by the financial consultant, a portion of the losses of Loss Subsidiaries would be allocated to Taxpayer. This portion would be multiplied by 46 percent to determine the tax savings. The resulting amount of tax savings would then be used to reduce Taxpayer's current tax expense for purposes of determining its cost of service. It should also be noted that one or more of the non-regulated subsidiaries have shown a loss, but that the non-regulated utilities as a group have consistently shown a profit.

Section 168(e)(3) of the Code expands the limitations of section 167(l) and provides a special rule for public utilities wishing to utilize the benefits of the Accelerated Cost Recovery System (ACRS) with respect to public utility property. Basically, it requires normalization by stating --

(A) IN GENERAL. --

The term "recovery property" does not include public utility property (within the meaning of section 167 (1)(3)(A)) if the taxpayer does not use normalization method of accounting.

(B) USE OF NORMALIZATION METHOD DEFINED. --

For purposes of subparagraph (A), in order to use a normalization method of accounting with respect to any public utility property --

(i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such

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purposes; and

(ii) if the amount allowable as a deduction under this section with respect to such property differs from the amount that would be allowable as a deduction under section 167 (determined without regard to section 167(l)) using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under subparagraph (B)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

(C) USE OF INCONSISTENT ESTIMATES AND PROJECTIONS, ETC. --

(i) IN GENERAL. -- One way in which the requirements of subparagraph (B) are not met is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with the requirements of subparagraph (B).

(ii) USE OF INCONSISTENT ESTIMATES AND PROJECTIONS. --

The procedure and adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (B)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other two such items and with respect to the rate base.

Section 167(l)(3)(G) of the Code provides, with minor exceptions, the same definition for the normalization method of accounting as found in section 168(e)(3)(B) above.

Section 1.167(1)-1(a)(1) of the Income Tax Regulations in describing the scope of section 167(1) states, in part, the following:

The normalization requirements of section 167(1) with respect to public utility property defined in section 167(1)(3)(A) pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation under section 167 and the use of the straight line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account.

Section 1.167(1)-1(h)(1)(iii) of the regulations in further defining the normalization method of accounting states, in part, as follows:

* * * the amount of Federal income tax liability deferred as a result of the use of different method of depreciation under subdivision (i) of this subparagraph is the excess (computed without regard to credits) of the amount the tax liability would have been had a subsection (1) method been used over the amount of the actual tax liability. Such amount shall be taken into account for the taxable year in which such different methods of depreciation are used.

The Service does not determine such purely regulatory questions as whether the proposals of a Commission will produce just and equitable rates, nor does it discuss the relative merits of "stand- alone" or other methods of regulatory accounting. The Service in this ruling request determines only whether Taxpayer will be in compliance with the normalization provisions of the Code if the recommendation of the financial consultant were to be finally adopted. To this end the following discussion is devoted.

Under the provisions of section 1.167(1)-(1)(h)(1)(i) of the regulations, Taxpayer will be regarded as using a normalization method of accounting with respect to its public utility property only if it makes an adjustment to a reserve to record the deferral of income taxes resulting from the use of a different method of depreciation for income tax purposes than is used for ratemaking purposes.

From the description of the normalization method in section 1.167(1)-(h) (1)(iii) of the regulations it is evident that the amount of federal income tax liability deferred for normalization purposes involves only

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two variables: the depreciation deduction for ratemaking purposes on the one hand, and the depreciation deduction actually used for federal income tax purposes on the other hand. The amount of federal income tax liability so deferred in a given year is, therefore, simply the product of the difference between these depreciation deductions and the federal income tax rate in effect for the year.

If Taxpayer were to introduce a variable, such as the tax benefits resulting from the tax losses of affiliates that served to reduce the amount of federal income tax liability deferred under section 1.167(1)-1(h)(1)(iii) of the regulations, Taxpayer would no longer be regarded as using a normalization method of accounting. Not only would the tax deferral, so reduced, be inadequate to meet the normalization requirements, reduction would have the same effect as the kind of adjustment to the reserve that is prohibited by section 1.167(1)-1(h)(2). Such an adjustment achieves through current tax expense a cost of service reduction that would violate normalization requirements if achieved through a reduction of deferred tax expense, and the effect is the same as if there were a partial flow-through of the benefits of accelerated depreciation as a result of deferring less than all the difference between straight line and accelerated depreciation. By either view, the use of tax benefits attributable to other entities in the determination of deferred tax expense or current tax expense will cause Taxpayer to fail to comply with the normalization provisions of the Code and the regulations thereunder.

There is an additional reason why the method proposed by the financial consultant would violate the normalization provisions. Sections 168(e)(3)(C) and 167(l)(3)(G) of the Code require consistency with respect to the assumptions used for the computation of tax expense, depreciation expense, deferred taxes and rate base. Under the proposed method, losses of Loss Subsidiaries would be used for purposes of determining Company's regulated tax expense. However, Loss Subsidiaries are ignored for purposes of determining Company's rate base as well as its depreciation expense. None of Loss Subsidiaries' assets are included in Taxpayer's rate base and none of the depreciation of Loss Subsidiaries' assets is included in Taxpayer's depreciation expense for cost of service purposes. This lack of consistent assumptions violates section 168(e)(3)(C) and 167(l)(3)(G) of the Code.

Therefore, based on the above represented facts and our legal analysis, we rule that:

Taxpayer will not be in compliance with the normalization requirements of sections 167(l) and 168(e)(3) of the Code, if, in computing its total expense for purposes of establishing its cost of service for ratemaking purposes, its current tax expense is reduced by a portion of the tax savings attributable to the tax losses of Loss Subsidiaries.

This ruling is directed only to the taxpayer who requested it. Section 6110(j)(3) of the Code provides that it may not be used or cited as precedent. Temporary or final regulations pertaining to one or more of the issues addressed in this ruling have not yet been adopted. Therefore, the ruling will be modified or revoked by adoption of temporary or final regulations, to the extent the regulations are inconsistent with any conclusions in the ruling. See section 17.04 of Rev. Proc. 86-1, 1986-1 I.R.B. 6, 17. However, when the criteria in section 17.05 of Rev. Proc. 86-1 are satisfied, a ruling is not revoked or modified retroactively, except in rare or unusual circumstances.

A copy of this private letter ruling is being sent to your authorized representatives in accordance with the power of attorney on file with this office.

A copy of this ruling letter should be filed with the income tax return for the taxable year or years in which the transaction covered by this ruling is consummated.

Sincerely yours,
Anthony Manzanares
Acting Director, Corporation
Tax Division

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LTR 8711050

Section 167 -- Depreciation Deduction

UIL Number(s) 0167.23-00, 0168.00-00

Summary

ADJUSTMENT FOR TAX SAVINGS BY UTILITIES IN CONSOLIDATED GROUP DOES NOT MEET NORMALIZATION REQUIREMENTS.

A company is the parent of a controlled group of companies that provide a wide variety of communication and information processing products and services. A number of these companies are regulated utilities, primarily local telephone companies, while others are unregulated companies. Some of the members of the parent's consolidated group have experienced substantial taxable losses which include the maximum deductions allowable for depreciation, resulting in corresponding reductions in consolidated taxable income reported by the group. Also, investment tax credits (ITCs) that could have been used by a number of the companies on a separate return basis have been utilized, due to the filing of a consolidated return, to offset tax currently.

During a review of a request for an increase in local rates, the local rate commission hearing the request and a consumer advocate proposed adjustments to each of the parent's utility subsidiaries' computed Federal income tax expense for "tax savings" as the result of filing a consolidated Federal income tax return. The consumer advocate testified that an adjustment should be made in establishing cost of service to reflect the utilities' pro rata share of separate affiliated companies; losses and credits used for purposes of the consolidated tax return but not utilized on a separate return. The commission adopted an adjustment by calculating the tax savings attributable to the consolidation of the returns, reduced for losses of the regulated companies, and the use the average savings as a deduction to determine the adjustment to figure tax savings.

The Service has held that the parent's utility subsidiaries will not be in compliance with the normalization requirements of sections 167(l) and 168(e)(3) if they use the consolidated tax savings adjustment proposed by the commission to determine the cost of service tax expense. The Service found that the use of this amount results in the current element of tax expense being lower than current tax expense computed at the statutory rate. The Service noted that if the parent introduced this type of adjustment for the tax benefits resulting from tax losses of affiliates that would reduce the tax liability deferred under regulations section 1.167(l)- 1(h)(1)(iii), the parent would no longer be regarded as using a normalization method of accounting.

Full Text

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Date: December 15, 1986

Refer Reply to: CC:C:E:1:2 - TR-31-33301-86

In re: Private Letter Ruling Request

Legend:
Taxpayer = * * *
Commission = * * *
Consumer Advocate = * * *
Court = * * *
Subsidiaries = * * *
State Y = * * *
Rate Cases = * * *

Dear * * *

We received your request for a private letter ruling dated July 30, 1986, and all subsequently filed data. Your request generally pertains to the normalization provisions of sections 167(1) and 168(e)(3) of the Internal Revenue Code. Specifically, you have requested the following ruling:

> That Taxpayer's State Y Subsidiaries will not be in compliance with the normalization requirements of sections 167(1) and 168(e)(3) of the Code if Subsidiaries use the consolidated tax savings adjustment proposed by Commission that, for purposes of determining cost of service tax expense, results in the current element of tax expense being lower than current tax expense computed at the statutory rate.
>
> You have made the following representations:

Taxpayer is the parent company of a controlled group of companies that provide a wide variety of communication and information processing products and services. A number of these companies are regulated utilities, primarily local telephone companies. Others engage in a variety of unregulated activities, including some companies that sell a portion of their goods to regulated sister companies. Taxpayer files a consolidated federal income tax return. Both Subsidiaries are regulated public utilities engaged in providing telephone service in State Y.

Over the past several years some of the members of Taxpayer's consolidated return group, primarily unregulated companies, have experienced substantial taxable losses which include the maximum deductions allowable for depreciation, resulting in corresponding reductions in consolidated taxable income reported by the group. Additionally, investment tax credits (ITC's) that could not have been utilized by a number of the companies on a separate return basis have been utilized, due to the filing of a consolidated return, to offset tax currently.

As part of a request for a current increase in local rates (Rate Cases), Taxpayer's State Y Subsidiaries included a federal tax expense in establishing their cost of service. To compute federal tax expense, each company applied a 46 percent tax rate to "cost of service taxable income." Cost of service taxable income was determined with the same depreciation expense used for other cost of service purposes. (Each Subsidiary uses accelerated depreciation under sections 167 and 168 of the Code in determining taxable income.) Further, cost of service taxable income was computed on a stand alone basis--only those revenue and expense items otherwise considered in determining jurisdictional cost of service were included. Additionally, adjustments were made in arriving at cost of service taxable income for those items that are not required to be normalized under the provisions of the Code. ITC's were deferred and ratably flowed through as a cost of service reduction pursuant to each Subsidiary's section 46(f)(2) elections in effect. In addition, as required under sections 167(1) and 168(e)(3), each Subsidiary made adjustments to

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a reserve to reflect the deferral of taxes resulting from the use of different methods of depreciation for tax and ratemaking purposes.

Both Commission Trial Staff and Consumer Advocate presented testimony proposing adjustments to each of Taxpayer's State Y Subsidiaries' computed federal income tax expense for "tax savings" resulting from Taxpayer's filing of a consolidated federal income tax return. Consumer Advocate's witness testified that a consolidated tax savings adjustment should be made in establishing cost of service tax expense to reflect Taxpayer's State Y Subsidiaries' prorata share of separate affiliated companies; losses and credits utilized in the consolidated federal income tax return but not utilized on a separate company basis. /1/

With respect to each Subsidiary, Commission's Opinion and Order dated * * * included a consolidated tax savings adjustment in the determination of the allowable revenues. On * * * Court granted a stay of the rate proceedings pending receipt of the ruling which is the subject of this request. The adjustment adopted by Commission is referred to as the consolidated tax savings adjustment" herein. The methodology used by Consumer Advocate to determine the adjustment amount is described as follows:

> The first step in my calculations was to compare the taxes which the members of Taxpayer would have paid on a separate re- turn basis to the actual consolidated income taxes of the system to determine the savings from consolidation in each year (* * * in final adopted adjustment). I then reduced these savings to exclude those amounts resulting from the losses of regulated companies. I then determined Subsidiaries' share of the net savings in each year based on their tax liability on a separate return basis compared to the total liability of all members of Taxpayer on a separate return basis. Finally, I averaged the tax savings for the years * * * through * * * (* * * through * * * in final adopted adjustment) and applied the intrastate factor for income tax deductions to determine my adjustment.

The adjustment, as calculated above, was then limited to no more than Taxpayer's State Y Subsidiaries' current tax expense. No other adjustments were made to the tax expense nor were any adjustments made to the deferred tax balances, depreciation or ITC.

Section 168(e)(3) of the Code expands the limitations of section 167(1) and provides a special rule for public utilities wishing to utilize the benefits of the Accelerated Cost Recovery System (ACRS) with respect to public utility property. Basically, it requires normalization by stating--

> (A) IN GENERAL.--

The term "recovery property" does not include public utility property (within the meaning of section 167 (1)(3)(A)) if the taxpayer does not use a normalization method of accounting.

> (B) USE OF NORMALIZATION METHOD DEFINED.--

For purposes of subparagraph (A), in order to use a normalization method of accounting with respect to any public utility property--

> (i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for rate-making purposes and reflecting operating results in its regulated books of account use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes; and
>
> (ii) if the amount allowable as a deduction under this section with respect to such property differs from the amount that would be allowable as a deduction under section 167 (determined without regard to section 167(1)) using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under subparagraph (B)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting

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from such differences.

(C) USE OF INCONSISTENT ESTIMATES AND PROJECTIONS, ETC.--

(i) IN GENERAL.--One way in which the requirements of subparagraph (B) are not met is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with the requirements of subparagraph (B).

(ii) USE OF INCONSISTENT ESTIMATES AND PROJECTIONS.--

The procedure and adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (B)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other two such items and with respect to the rate base.

Section 167(1)(3)(G) of the Code provides, with minor exceptions, the same definition for the normalization method of accounting as found in section 168(e)(3)(B) above.

Section 1.167(1)-1(a)(1) of the Income Tax Regulations in describing the scope of section 167(1) states, in part, the following:

The normalization requirements of section 167(1) with respect to public utility property defined in section 167(1)(3)(A) pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation under section 167 and the use of the straight line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account.

* * * (1)-1(h)(1)(iii) of the regulations in further defining the normalization method of accounting states, in part, as follows:

* * * the amount of federal income tax liability deferred as a result of the use of a different method of depreciation under subdivision (i) of this subparagraph is the excess (computed without regard to credits) of the amount the tax liability would have been had a subsection (l) method been used over the amount of the actual tax liability. Such amount shall be taken into account for the taxable year in which such different methods of depreciation are used.

The Service does not determine such purely regulatory questions as whether the proposals of a Commission will produce just and equitable rates, nor does it discuss the relative merits of "stand- alone" or other methods of regulatory accounting. The Service in this ruling request will determine only whether Taxpayer will be in compliance with the normalization provisions of the Code if Taxpayer were to use the consolidated tax savings adjustment ordered by Commission. To this end the following discussion is devoted.

Tax expense computed under a normalization method of accounting, as so defined, includes both current and deferred tax expense as those terms are commonly used for financial statement purposes. Each of these components is an integral part of tax expense and cannot be excluded. When the same method of depreciation that is used for tax calculations is used for establishing cost of service, the tax calculated is the sum of the two components.

From the description of the normalization method in section 1.167(1)-1(h)(1)(iii) it is evident that the amount of federal income tax liability deferred for normalization purposes involves only two variables; the depreciation deduction for ratemaking purposes on the one hand, and the depreciation deduction actually used for federal income tax purposes on the other hand. The amount of federal income tax liability so deferred in a given year is, therefore, simply the product of the difference between these depreciation deductions as defined in the regulations and the federal income tax rate in effect for the year. It is clear

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from the narrative portion of the regulations that the amount of tax deferral is the difference between actual income tax liability and what would have been the actual tax liability if a subsection (1) method of depreciation (straight line in this case) was substituted for the depreciation method actually used for federal income tax purposes. Inasmuch as all other items of income and deduction in the computation remain constant, the computation of tax deferral requires only the depreciation difference and the tax rate. Because actual federal income tax liability is determined pursuant to statute, normalization accounting requires the use of the federal income tax rate provided by section 11(b) of the Code. When the income subject to tax is in excess of $100,000, the rate to be applied is the marginal tax rate (currently 46 percent).

If Taxpayer were to introduce a variable, such as the tax benefits resulting from the tax losses of affiliates, that served to reduce the amount of federal income tax liability deferred under section 1.167(1)-1(h)(1)(iii) of the regulations, Taxpayer would no longer be regarded as using a normalization method of accounting. Not only would the tax deferral, so reduced, be inadequate to meet the normalization requirements, reduction would have the same effect as the kind of adjustment to the reserve that is prohibited by section 1.167(1)-1(h)(2). The consolidated tax savings adjustment achieves through current tax expense a cost of service reduction that would violate normalization requirements if achieved through a reduction of deferred tax expense, and the effect is the same as if there were a partial flow-through of the benefits of accelerated depreciation as a result of deferring less than all the difference between straight line and accelerated depreciation. The use of tax benefits attributable to other entities in the determination of deferred tax expense or current tax expense will cause Taxpayer to fail to comply with the normalization provisions of section 167(1) of the Code and the regulations thereunder.

The normalization requirements of section 168(e)(3) of the Code are similar to the normalization requirements in section 167(l). If a proposed method of accounting does not meet the normalization requirements of section 167(1) it will not meet the requirements of section 168(e)(3).

There is an additional reason why the consolidated tax savings adjustment would violate the normalization provisions. Sections 168(e)(3)(C) and 167(1)(3)(G) of the Code require consistency with respect to the assumptions used for the computation of tax expense, depreciation expense, deferred taxes and rate base. The consolidated tax savings adjustment improperly includes the transactions of a11 affiliates in determining ratemaking tax expense without giving consideration to such transactions in any other ratemaking calculations. That is to say, in developing tax expense, Taxpayer's State Y Subsidiaries have not been viewed as standing alone but as a part of the entire group, whereas for every other ratemaking purpose these companies have been viewed as stand alone. This lack of consistent assumptions violates sections 167(1) and 168(e)(3) of the Code.

Therefore, based on the above represented facts and our legal analysis, we rule that:

> Taxpayer's State Y Subsidiaries will not be in compliance with the normalization requirements of sections 167(1) and 168(e)(3) of the Code if they use the consolidated tax savings adjustment proposed by Commission that, for purposes of determining cost of service tax expense, results in the current element of tax expense being lower than current tax expense computed at the statutory rate.

This ruling is directed only to the taxpayer who requested it. Section 6110(j)(3) of the code provides that it may not be used or cited as precedent. Temporary of final regulations pertaining to one or more of the issues addressed in this ruling have not yet been adopted. Therefore, the ruling will be modified or revoked by adoption of temporary or final regulations, to the extent the regulations are inconsistent with any conclusions in the ruling. See section 17.04 of Rev. Proc. 86-1, 1986-1 I.R.B. 6, 17. However, when the criteria in section 17.05 of Rev. Proc. 86-1 are satisfied, a ruling is not revoked or modified retroactively, except in rare or unusual circumstances.

A copy of this private letter ruling is being sent to your authorized representatives in accordance with the power of attorney on file with this office.

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A copy of this ruling letter should be filed with the income tax return for the taxable year or years in which the transaction covered by this ruling is consummated.

Sincerely yours,

Anthony Manzanares
Acting Director, Corporation
Tax Division

/1/ The separate affiliated companies are not subsidiaries of Taxpayer's State Y Subsidiaries. They include the parent and brother sister companies involved in unrelated activities.

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Docket No. NG02-011

BEFORE THE

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

Rebuttal Testimony

of

Russell A. Feingold

on behalf of

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.

June 2003

NAVIGANT
CONSULTING

REBUTTAL TESTIMONY OF RUSSELL A. FEINGOLD

Q. Please state your name and business address.

A. My name is Russell A. Feingold and my business address is 200 Wheeler Road, Suite 400, Burlington, Massachusetts 01803. I am employed by Navigant Consulting, Inc. ("NCI") as a Managing Director and lead its Regulatory & Fuel Resources Practice.

Q. Have you presented testimony previously in this proceeding?

A. Yes. I filed direct testimony on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company"), a Division of MDU Resources Group, Inc. that addressed certain gas rate design concepts that the Company had evaluated in formulating its rate proposal in this proceeding. Specifically, I discussed the conceptual underpinnings and industry-wide trends associated with the Company's proposal to enhance the recovery of its gas distribution margin through rate design. I also provided an overview and analysis of an alternative ratemaking mechanism that Montana-Dakota could apply to its heat sensitive classes of service.

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

A. The purpose of my rebuttal testimony is to respond to certain points raised by

Messrs. Martin C. Bettmann and Robert G. Towers on behalf of the South Dakota Public Utilities Commission ("Commission") Staff concerning the Company's class cost of service study and to address the Commission Staff's related criticism of the Company's various fixed monthly charges as part of its gas rate design proposal. In addition, I will respond to Staff's review of the Company's alternative Distribution Delivery Stabilization Mechanism ("DDSM") proposal.

Q. Would you please identify the specific points addressed by Mr. Towers to which you will respond?

A. Yes. Mr. Towers has made certain contentions regarding the Company's gas cost of service study that he has presented in his direct testimony. Specifically, he disagrees with the Company's inclusion of a customer component in its classification of the cost of Distribution Mains ("Mains"). He recommends that the cost of Mains be allocated among the customer classes entirely on the basis of customers' peak demand requirements. This recommendation also affects the derivation of other composite allocation factors employed in the Company's cost of service study, which shifts costs away from the Residential class to all other classes. Based on the resulting changes to the Company's cost study, Mr. Towers concludes that the entire rate increase should be assigned to the Firm General Service class.

Mr. Towers further contends that the Company's cost support for the proposed

monthly Service Charges is overstated because "it includes many costs that are not directly related to the service rendered to individual customers, including the customer component of Mains…." I will address the customer cost analysis prepared by Mr. Towers and its use in setting monthly customer charges.

Q. Would you please identify the specific points addressed by Mr. Bettmann to which you will respond?

While Company witness Aberle will respond to specific points raised by Mr. Bettmann regarding the Company's various rate design proposals, I will comment on the concerns expressed by Mr. Bettmann regarding the Company's alternative rate design concept reflected in its Distribution Delivery Stabilization Mechanism ("DDSM").

Q. Please summarize your conclusions regarding the issues outlined above.

A. The Company's approach to classifying a portion of Mains cost as customer-related best reflects the true cost of connecting customers to its gas distribution system. This approach recognizes one of the two cost causative factors associated with Mains within the context of a cost of service study.

In contrast, the cost of service study supported by Staff witness Mr. Towers fails to adequately capture the costs of serving the Company's various classes of service. The Staff's cost study falls short from a conceptual perspective. As a

result, I conclude that the Staff's cost of service study results should not be relied upon by the Commission for determining the Company's class revenue levels and unit rate levels. Instead, the Commission should rely upon the Company's filed cost of service study because it best reflects the costs incurred to serve Montana-Dakota's customers.

The customer charge levels proposed by Staff are inappropriate by virtue of its reliance upon a cost of service study that is conceptually flawed. Therefore, the Commission should reject these "status quo" rate proposals, and should instead accept the Company's proposal regarding the recovery of customer-related costs as an important step in the pricing of utility services to accomplish its rate structure objectives. These objectives were previously discussed in Ms. Aberle's Direct Testimony, which include providing a measure of stability for Montana-Dakota's customers during periods of abnormal weather, having easily understandable rates for customers, having a rate form that is simple to administer, and enhancing fixed cost recovery.

Finally, the Company believes the issues raised by the Staff concerning the Company's alternative Distribution Delivery Stabilization Mechanism ("DDSM") proposal can be adequately addressed by incorporation of certain methodological changes that are widely recognized in the gas distribution industry in the design of similarly situated ratemaking mechanisms.

Q. Do you disagree with Mr. Towers' assertion that it is inappropriate to recognize a customer cost component associated with Mains?

A. Yes. To ensure that the customer classes on whose behalf the plant investment or expense was incurred are charged with their proper costs, Mains should be allocated to those classes in proportion to their peak day load requirements and number of customers. There are two cost factors that influence the level of Mains facilities installed by Montana-Dakota in expanding its gas distribution system. First, the size of the Main (i.e., the diameter of the main) is directly influenced by the sum of the coincident peak day gas demands placed on Montana-Dakota's gas system by its customers. Second, the total installed footage of Mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize the fact that these two cost factors influence the level of investment in Mains, it is appropriate to allocate such investment based on both peak demands and the number of customers served by Montana-Dakota.

Q. Please comment on Mr. Towers' argument at page 16 of his Direct Testimony that "(T)he 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."

A. Mr. Towers is incorrect in his claim for a number of reasons. There is strong engineering and cost support for establishing a customer component of Mains. To better understand the underlying reasons for this support, it is important to first provide some background perspectives on the installation of Mains. Installation of new Mains or the upgrade of an existing segment of pipeline is usually required in response to growth in a Local Distribution Company's ("LDC") hourly peak demand. Demand growth occurs for one or more of the following reasons:

1) Existing customers increase their coincident peak hour demands.

2) New residential, commercial and industrial customers locate within the existing system of distribution mains.

3) New residential, commercial and industrial customers locate beyond the existing system of distribution mains.

Mr. Towers alluded to these reasons for demand growth in his Direct Testimony where he states that gas distribution networks "are the result of system expansion ... into new service territories in response to area development" and "to satisfy changes in the requirements of customers in existing service areas." Each of these reasons contributes to an increase in the LDC's investment in Mains, due to an increase in peak demands. In the case of the third reason, the Company's analysis and resulting customer component of Mains gives recognition to the need to extend the LDC's distribution system mains to connect this new customer to the LDC's existing distribution grid.

The construction cost estimates associated with connecting a new customer to the Company's gas distribution system are always based upon the capacity level

1 necessary to meet each customer's peak hour demands. An excellent proxy for
2 the peak hour demands used in distribution cost estimating is the customer's
3 design day demand. At the same time, that construction cost estimate for each
4 customer will be premised upon how far the customer is located from the
5 Company's existing distribution grid and the demands expected to be imposed
6 on the system by the customer. The recognition of a customer component of
7 Mains simply captures the cost causation aspects of these utility construction
8 characteristics.
9
10 **Q. With regard to customers' service objectives, Mr. Towers states, "from the**
11 **customer's perspective, the distribution Mains are desired as a source of**
12 **gas supply -- not merely as a facility that exists merely for access." In your**
13 **opinion, is this a critical distinction that should be considered in the**
14 **determination of the cost causation elements related to Mains?**
15
16 A. No. Mr. Towers was asked to explain this distinction in a Company data request.
17 He responded to Data Request No. 44 that, "(c)ustomers of a gas utility become
18 customers to satisfy their needs for the gas commodity. These needs
19 encompass both the customer's average and peak requirements for gas. Rarely,
20 if ever do these "needs" include merely the need for access to the system without
21 no intention of purchasing gas." Mr. Towers' comments suggest a preference
22 for a system utilization basis for the allocation of distribution system costs that
23 relies solely on the energy consumption characteristics of customers. He affirms
24 this preference in his statement at page 18 of his Direct Testimony where he

states that, "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)." This is equivalent to the concept of a "commodity delivery function," which relates to the simple fact that an LDC delivers a gas commodity through its distribution system.

Taken to its logical end, Mr. Tower's concept would argue for all costs being allocated on the basis of customers' energy consumption characteristics. Obviously, this makes no sense whatsoever because it would result in a pure volumetric cost allocation supporting equal gas rates to all customers. In stark contrast to this overly simplistic approach to cost allocation, the customer and demand based allocation factors used in the Company's cost of service study are more strongly related to the Company's engineering and operational practices discussed earlier, which drive distribution mains investment over time, than are commodity or throughput based allocation factors.

Q. Have you analyzed the relationship between the number of customers served by Montana-Dakota and its level of investment in Mains?

A. Yes, I have. Exhibit No.___(RAF-R1) presents a linear regression analysis that regresses the Company's numbers of customers served against the footage of mains it has installed over the period, 1997 through 2002. This analysis and related statistical results indicates that the level of customers is strongly correlated to the footage of mains. Approximately 99.5% of the variation in

Montana-Dakota's footage of mains can be explained by the variation in the number of customers. As would be expected, as the number of customers served by Montana-Dakota increases, the level of investment in Mains, as measured by installed footage, also increases.

Q. Mr. Towers states at page 17 of his Direct Testimony "there is no physically identifiable "customer component" of Mains. Montana-Dakota creates this component by hypothesizing a system of zero or minimum size Main necessary to connect a customer to the system." Do you concur with Mr. Towers' characterization of the customer component as hypothetical and unidentifiable?

A. No. A customer component of Mains is fully supported by the realities of gas utility operations. Recognizing that our goal is to more reasonably classify and allocate the total cost of Montana-Dakota's distribution mains facilities, it is reasonable to analyze the cost causative factors that relate to these facilities based on the total number of customers served from these facilities. Accordingly, the concept of using a minimum system approach for classifying Mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of Mains investment to receive gas service. Thus, it is entirely appropriate to conclude that the number of customers served by Montana-Dakota represents a primary causal factor in determining the amount of Mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component is a distinct

and separate cost category of Mains, which is supported from an engineering and operating standpoint. Moreover, its conceptual appeal has been widely recognized by many experts in the field of public utility regulation.

Q. Can you briefly cite examples to support your statement that many experts recognize the concept of a customer cost component of Mains?

A. Yes. In his widely utilized text, The Regulation of Public Utilities, Dr. Charles F. Phillips, Jr. states, "customer costs vary with the number of customers. These costs include a portion of the distribution system, local connection facilities, metering equipment, meter reading, billing and accounting. Customer costs, moreover, are independent of consumption."

In Gas Rate Fundamentals, it is stated that customer-related costs are primarily distribution and customer accounting costs. In conjunction with its discussion of various utility cost components, it is further stated that "the closer a plant item (e.g., a meter and service line) is located to a customer, the more that particular item is related to the specific requirements of that customer. Thus, the customer component of distribution costs reflects the theoretical distribution system that would be needed to serve customers at nominal or minimal load conditions." Additionally, in discussing the various functions and cost causation components attributable to the operations of a gas distribution utility, it is stated that for distribution costs, the prime cost causation component is one that is customer-related.

In Principles of Public Utility Rates, Professor Bonbright notes that the use of a two-part rate structure is based on the assumption that one part of the total costs of a utility's business is a function of the output or energy of the system, whereas another part is a function of plant capacity and hence of all costs related to this capacity. Professor Bonbright goes on to point out, however, that "this two-fold distinction overlooks the fact that a material part of the operation and capital costs of a utility business is more directly and closely related to the number of customers than to energy consumption on the one hand or maximum kilowatt demand on the other hand." (Emphasis added).

In addition, in the section dealing with the criteria of a sound rate structure, Professor Bonbright states, "customer costs incurred to serve a customer are invariant with respect to consumption. They are the costs incurred to serve a customer even if the customer does not use the service at all. The most obvious examples of these customer costs are the expenses associated with local connection facilities, metering equipment and meter reading, billing and accounting, and a portion of the distribution system."

Finally, at page 492, Professor Bonbright states, "in actual practice the vast majority of utilities utilized some form of minimum system to classify costs, which is in line with the FERC accounts."

Q. Mr. Towers suggests that "any number of varying results could be obtained

from MDU's (Montana-Dakota) data" and that a minimum system of any size has delivery capacity – "a fact that is inconsistent with the effort to identify a pure "customer component." Do you agree with his conclusion?

A. No. Notwithstanding Mr. Towers "what if" exercise in substituting one pipe material type and size for another in deriving different unit costs and thus varying levels of customer cost, recognizing that the most commonly installed minimum system carries some level of capacity is irrelevant to the determination of a customer component of Mains. Of course, the capability to serve all of the customers' demands is only accomplished by the Company's entire integrated gas distribution system, including the peak capacity of the upstream, larger diameter Mains. The most commonly installed minimum system method for determining the customer-related cost of Mains is simply a means of identifying that portion of the investment in Mains attributable to one of the two primary cost factors, the need to extend the distribution system grid to connect new customers.

Q. At page 21 of his Direct Testimony, Mr. Towers discusses his contention that the Company's cost support for its Basic Service Charges is "greatly overstated" because it includes costs that "do not vary as customers are added or leave the system." He cites the customer component of Mains as an example where "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." Do you concur with this

definition of eligible customer-related costs for the Basic Service Charge?

A. No. Development of the Company's distribution grid over time is a dynamic process, as Mr. Towers describes in his Testimony at page 16. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's "off-system" location.

Similarly, some of the other costs that Mr. Towers would consider eligible for the Basic Service Charge, such as meter reading expense, the installed cost of service lines, meters and regulators will not vary significantly with every customer that is added or leaves the system. In fact, very few costs (e.g., postage) will vary in such a direct manner. As the overall level of customers changes over time, however, these customer-related costs will change.

In his response to a data request on this subject (Request No. 39), Mr. Towers fails to recognize the aforementioned situation where the distribution main must be extended to serve a new customer. He states that, "When a customer applies for service, MDU does not build a new main." However, he does

acknowledge the lack of direct variability of customer-related costs when he states in the same response, "Indeed, it (MDU) does not even hire a new meter reader, although Mr. Towers treats meter reading as a cost that is directly related to service to a customer."

Mr. Towers' position on this topic at various points in his Direct Testimony is difficult to reconcile. At page 22 of his Direct Testimony, Mr. Towers defines customer costs as "costs directly related to maintaining customer service" while his earlier characterization of customer costs on page 5 rejects certain costs as "independent of incremental changes in the customer population." When asked to reconcile these two statements in a data request (Request No. 43), Mr. Towers adds little clarification when he states, "...Mr. Towers' testimony clearly indicates that the statement on page 22...referring to costs that are *directly* (i.e. *not indirectly*) related to customer service are those costs which are physically identifiable with an individual customer and which necessarily will increase as a customer is added to the system." The fact remains that the aforementioned costs of providing gas service to a customer are fixed, regardless of the quantity of gas the customer consumes or whether the customer uses the service at all, and should be regarded as customer-related and eligible for inclusion in the Basic Service Charge.

In any event, Mr. Towers' concept of examining only incremental costs for purposes of deriving appropriate monthly customer charges is irrelevant within the context of performing an <u>embedded</u> cost of service study.

1

2 **Q. What is your reaction to Mr. Towers' contention at page 5 of his Direct**
3 **Testimony that if direct customer-related costs are recovered through non-**
4 **gas commodity charges, thus "putting such costs at risk," it provides the**
5 **Company with "a cost control incentive?"**

6

7 A. I find it rather ironic that the same categories of customer-related costs that meet
8 Mr. Towers' definition as "affected, incrementally, when a customer is added to
9 the system" could somehow provide a further cost control incentive beyond that
10 which prudent management of the LDC would otherwise dictate, unless he would
11 have customers somehow share the use of meters, regulators and services in an
12 effort to control these costs.

13

14 Mr. Towers was asked in a data request (Request No. 36) to fully define the
15 source and type of risk to which these costs would be subject and explain the
16 basis for his statement that this risk would provide a cost control incentive not
17 otherwise present. He responded as follows - "If costs that are relatively fixed in
18 the short run are recovered through a regulated company's volumetric rates, a
19 decline in sales volumes to a level that is measurably lower than the ratemaking
20 expectation may cause the company to earn something less than its allowed
21 return. This is earnings risk. If the decline is expected to be temporary (e.g. a
22 deviation from normal weather) its effect on efficiency incentives would likely be
23 negligible. However, it the decline is expected to be one of longer duration, the
24 company can be expected to act to reduce costs to restore its earnings."

From this response, it is clear that Mr. Towers would characterize any variations in gas sales volumes due to varying weather conditions as "temporary" in nature. These are the same conditions that caused the Company to propose the various ratemaking changes presented in this rate case. As such, under these short-term conditions, Mr. Towers' response also makes it clear that he would not expect the creation of any meaningful "cost control incentive" from the recovery of customer-related costs through non-gas commodity charges.

Mr. Towers' response then quotes a passage from the Company's 2002 Annual Report allegedly to reinforce his notion that, "(t)he loss of earnings capability or opportunities or even the expectation of such losses creates incentives for greater efficiency, to wit:

> "...Each business unit and every employee recognized that the country was facing challenges that could affect our businesses. They recognized that we needed to pull together and be innovative in order to succeed in times like these. I am happy to report that is exactly what happened." (Letter from Chairman of the Board, President and CEO Martin A. White as published in MDU's 2002 Annual Report, pp. 2-5)."

While Mr. Towers' limited quotation would have you believe that the focus of the Company's activities is on cost control during tough times, a more complete reading of its Letter from the Chairman tells a very different story – a focus on earnings growth, in large part, through a reinforcement of its culture of

1 innovation. The theme of the Letter demonstrates management's forward
2 thinking approach to pursuing growth opportunities in its various business lines
3 through broad business initiatives of innovation, operational excellence,
4 employee growth and development, that are an integral part of the Company's
5 "daily process" or culture. The following statement in Mr. White's Letter
6 evidences this business culture:
7
8 "I believe we need to be continually evolving our business, to evaluate
9 what we're doing and where we're going. Some businesses only do this in
10 times of crisis. At MDU Resources, it's a daily process."
11
12 Clearly, Montana-Dakota does not require Mr. Towers' so-called "cost control
13 incentive" by subjecting its fixed, customer-related costs to the risk of recovery
14 through its volumetric charges in order to manage its business efficiently.
15
16 **Q. Do you have any comments concerning Mr. Bettmann's discussion of the**
17 **Company's Distribution Delivery Stabilization Mechanism ("DDSM")**
18 **alternative?**
19
20 A. Yes, I do. Two of the three reasons cited by Mr. Bettmann for disagreeing with
21 the Company's DDSM alternative are related to the time lag between when the
22 true up occurs and when the associated revenues are collected or dispersed. On
23 page 9 of his Direct Testimony, Mr. Bettmann states "(A)fter each heating
24 season, the under or over recovery of fixed costs would be collected or dispersed

during the following year. During that time customers may have moved on or off the system and those true-up amounts will end up being charged or credited to customers not responsible for those expenses or credits." Mr. Bettmann's second concern, also time lag related, involves the prospect of a warmer than normal heating season, which would generate a positive adjustment to be calculated for the following heating season, followed by a colder than normal heating season. Under this scenario customers would experience the cost of the DDSM adjustment as well as the cost of purchasing larger volumes of gas, at potentially higher prices.

These concerns could be adequately addressed by modifying the DDSM from an annual lagged adjustment (e.g., the adjustment appears on customers' bills several months after the variation in weather is experienced) to adjusting current billings on a real-time basis. These are the two basic approaches that can achieve the desired results. Of the roughly thirty-five mechanisms in use today by gas utilities throughout the U.S. to adjust rates for weather variability, approximately three-quarters of these mechanisms employ the real-time approach to billing. By adjusting current billings on a real-time basis, the consumer can more readily link the resulting billing adjustments with the events causing the adjustments. An additional benefit associated with the real-time approach, the utility's financial statements will reflect the revenue normalizing effect of the mechanism sooner than under a lagged mechanism.

Q. What is the third reason cited by Mr. Bettmann for his disagreement with

the Company's DDSM proposal?

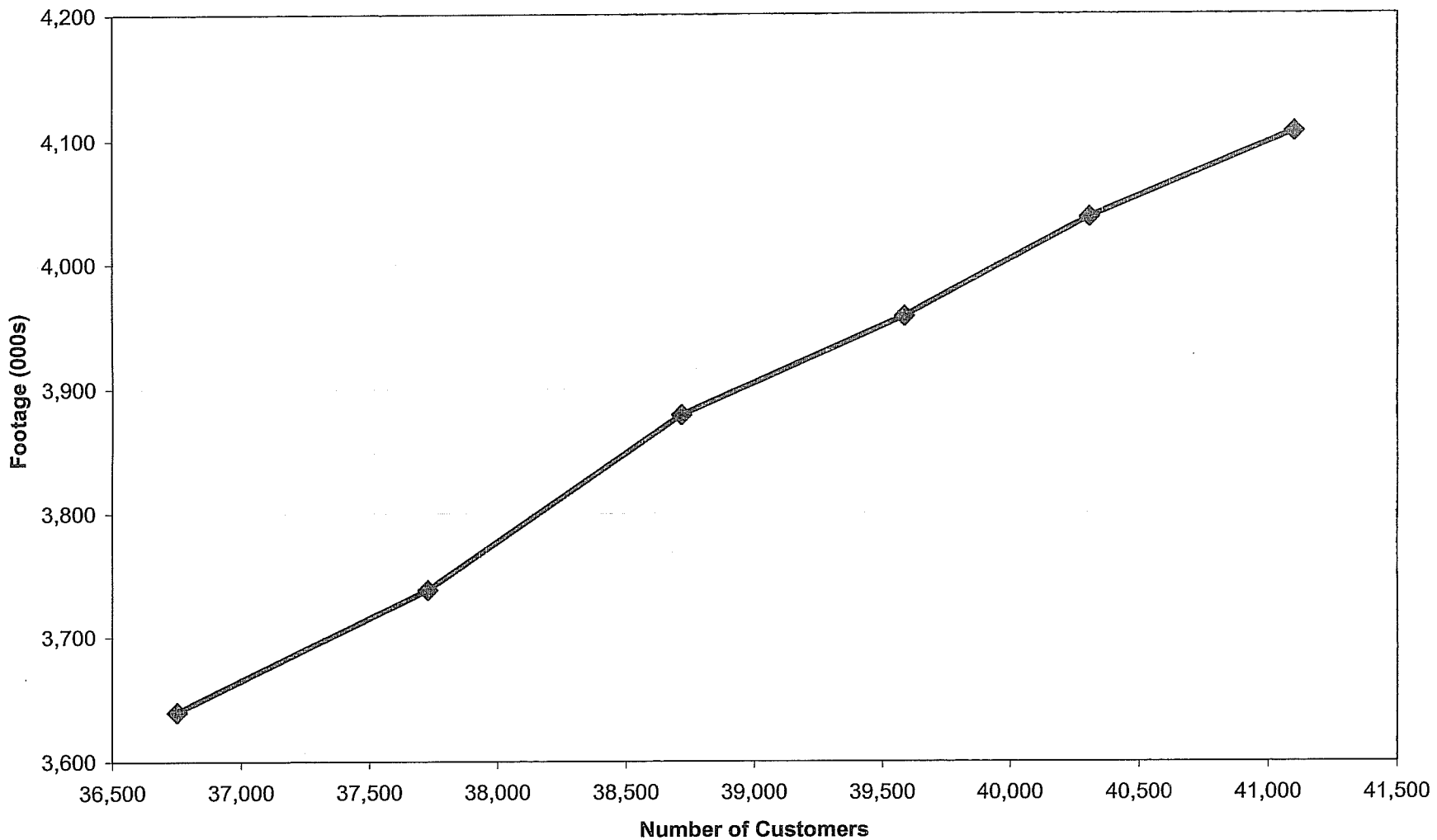
A. Mr. Bettman discusses his third concern with the Company's proposed DDSM mechanism at lines 18-21 of page 9. He states that, "(I)t is also possible that due to variations in the weather in different parts of the Company's service area, customers in one area may be experiencing a colder or warmer heating season than in other areas and therefore those customers could receive or pay an unfair share of the DDSM adjustment."

Q. How would you propose to address this last concern of Mr. Bettmann?

A. I am somewhat reluctant to recommend attaching too much precision to what will comprise very small adjustments to the monthly bills of customers for system weather variations. In particular, this is due to the cross-subsidization that already exists within the Company's rate classes due to its largely volumetric rate structure, which would overshadow any geographic disparity in the recovery of the DDSM adjustment. However, Mr. Bettmann has provided both the potential solution and an example of its application in his response to one of the Company's data requests concerning this issue, Request No. 30. In a schedule accompanying his response, Mr. Bettmann provides an analysis of weather data from seven weather stations in the Company's service territory. The actual to normal heating degree day comparison shown in this schedule mimics the operation of the real-time adjustments that would be made to customers' monthly bills. While further analysis may indicate that seven geographically differentiated

1 weather adjustment factors is unwarranted for the Company's South Dakota
2 service territory, the DDSM can readily accommodate this type of adjustment in
3 order to address the fairness / equity concern raised by Mr. Bettmann.
4
5 **Q. Mr. Feingold, does that complete your rebuttal testimony?**
6
7 A. Yes, it does.

Montana-Dakota Utilities Co.
Relationship Between Footage of Mains (000s) and Number of Customers (1997-2002)



Docket No. NG02-011
Exhibit No.__(RAF-1)

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

Before the Public Utilities Commission of South Dakota

Docket No. NG02-011

Rebuttal Testimony
of
Tamie A. Aberle

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

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

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

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

8 Q. Are you the same Tamie A. Aberle who filed direct testimony in this
9 proceeding?

10 A. Yes, I am.

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

12 A. The purpose of this rebuttal testimony is to address rate design
13 recommendations and a proposed tariff change made by Mr. Martin C.
14 Bettmann and Mr. David A. Jacobson on behalf of the South Dakota
15 Public Utilities Commission Staff (Staff).

16 Q. Would you please explain why you do not agree with Mr. Bettmann's
17 recommendation regarding the proposed revenue allocation to the

1 Residential and Firm General Service classes?

2 A. Mr. Bettmann relied upon the class cost of service study presented
3 by Mr. Towers which is flawed for the reasons set forth in Mr. Feingold's
4 rebuttal testimony. Based on this misstated class cost of service study,
5 Mr. Bettmann recommends that the entire increase be allocated to the
6 Firm General Service class. As noted on page 3 of Mr. Feingold's
7 testimony, Mr. Towers' study fails to adequately capture the costs of
8 serving the Company's various classes of service. Mr. Feingold further
9 concludes that, "the Staff's cost of service study should not be relied upon
10 by the Commission for determining the Company's class revenue levels
11 and unit rate levels." As supported by the Company's class cost of
12 service study and as recommended in my direct testimony filed in this
13 case, the Residential and Firm General service classes both warrant an
14 increase in revenues.

15 Q. Do you agree with Mr. Bettmann's recommendation relative to the rate
16 structure for the Residential and Firm General Service classes?

17 A. No. It is inappropriate to retain the current declining block rate
18 structure with no change in the base rates applicable under either the
19 Residential or Firm General Service classes as recommended by Mr.
20 Bettmann. Again, based on Mr. Towers' flawed class cost of service
21 study, Mr. Bettmann concludes that no change in the base rates is
22 warranted. There is no cost basis to support a declining block rate
23 structure for gas service if other parts of the utility's rate structure are

1 established properly based on the cost to serve. The cost to provide gas
2 service to a customer does not decline as the energy consumed by a
3 customer increases. Montana-Dakota's firm gas service rates have
4 reflected a declining block rate structure for a number of years as a
5 means of moving toward a cost based fixed rate. By increasing the Base
6 Rate or Basic Service Charge to the level proposed by the Company, the
7 declining block rate may be eliminated. As stated in my direct testimony
8 the Company's rate structure proposal helps to achieve the objectives of
9 1) providing a measure of stability during periods of abnormal weather 2)
10 providing easily understandable rates for customers and 3) enhancing
11 fixed cost recovery. Furthermore, the Basic Service Charges proposed
12 by the Company are consistent with the fixed monthly charges applicable
13 in the gas distribution industry as supported by Exhibit No.____(RAF-1)
14 filed with Mr. Feingold's direct testimony in this Docket.
15 Q. Would you please comment on the Base Rates proposed by Mr.
16 Bettmann for the Firm General Seasonal, Small Interruptible Service,
17 Large Interruptible Service, Ellsworth Air Force Base and the Firm
18 Contract rate schedules?
19 A. Yes. Mr. Bettmann has proposed to tie the Base Rate applicable to
20 the Firm General Seasonal Rate 72 to the base rate applicable to Small
21 Interruptible Service Rate 71. This is not appropriate as the customers
22 taking service under the Firm General Seasonal rate are similar to the
23 customers taking Firm General Service Rate 70 and therefore the base

1 rate for the seasonal rate should be tied to Rate 70 as it is today. The
2 only other change proposed by Staff for the noted customer groups is to
3 increase the Base Rate applicable to the Small Interruptible Sales Rate 71
4 customers to $80.00 per month based on Mr. Towers' skewed class cost
5 of service study. This recommendation was based on a study which
6 indicates that the Small Interruptible customer costs are $122.72 while the
7 customer costs are $2.33 for the Air Force Base and $108.08 for the
8 Large Interruptible class. These customer cost results are not reasonable
9 based on metering cost differences between these classes alone,
10 irrespective of Mr. Towers' erroneous class cost of service study results.
11 Q. Would you please address the change Mr. Jacobson recommends be
12 made to the Company's proposal to increase the penalty for an
13 interruptible customer's failure to curtail or interrupt the use of gas service
14 upon request of the Company?
15 A. Yes. While Mr. Jacobson agrees that an increase in the current
16 penalty of $10.00 per dk for failure to interrupt is appropriate, he
17 recommends that the penalty be set at $30.00 rather than $50.00, as
18 proposed by the Company, due to the size of the increase and because
19 $30.00 has been accepted by the Commission in the past. Given the
20 intent is to penalize an interruptible customer for using natural gas
21 service, after a call to interrupt or curtail has been made by the Company,
22 and given the potential ramifications to the firm customers should
23 interruptible customers decide to continue to use natural gas after

1 receiving a curtailment or interruption notification, the $50.00 charge

2 should be approved as proposed.

3 Q. Does this conclude your rebuttal testimony?

4 A. Yes, it does.

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 MOTION TO EXTEND DEADLINE FOR REBUTTAL TESTIMONY NG02-011**

On December 30, 2002, 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 $2,173,380 or approximately 5.8%. On January 16, 2003, the Commission suspended the proposed schedule of rates for 90 days beyond January 30, 2003. On April 1, 2003, Commission Staff recommended that the suspension of the tariff be further extended for 60 days.

At its April 1, 2003, meeting, the Commission considered this matter. MDU concurred with Staff's recommendation. The Commission voted unanimously to grant the extension sought by Commission Staff. On April 30, 2003, the Commission received MDU's motion to continue and reschedule the hearing.

At its May 6, 2003, meeting, the Commission considered this matter. MDU agreed to suspend implementing the proposed rate increase for 30 days after the June 29, 2003, expiration date. The Commission voted unanimously to grant the continuance. On May 22, 2003, the Commission received MDU's motion to extend deadline for rebuttal testimony to June 6, 2003.

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 June 3, 2003, meeting, the Commission considered this matter. The Commission voted unanimously to grant MDU's motion to extend deadline for rebuttal testimony to June 6, 2003. It is therefore

ORDERED, that MDU's motion to extend deadline for rebuttal testimony to June 6, 2003, is granted.

Dated at Pierre, South Dakota, this 10th day of June, 2003.

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: 6/11/03

(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

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BOBBI J. BENSON
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OF COUNSEL
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KARL GOLDSMITH 1885-1966

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June 12, 2003

HAND DELIVERED

Pam Bonrud, Executive Secretary
Public Utilities Commission
500 East Capitol Avenue
Pierre, South Dakota 57501

RE: **IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE**
Docket: NG02-011
Our file: 4165

Dear Pam:

Enclosed is the original counterpart of MDU's Third Request for Confidential Treatment of Information filed pursuant to ARSD 20:10:01:41, which please file. This relates to a document that was filed with MDU's rebuttal testimony. In the past we have filed only one counterpart of the request for confidential treatment of information, since there are no intervenors and Commission staff is obtaining a copy of this filing. If you require more counterparts, please let me know, and I will file them.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

DAVID A. GERDES
DAG:mw
Enclosure
cc/enc: Karen Cremer
Dave Jacobson
Don Ball
Rita Mulkern

RECEIVED

JUN 12 2003

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF	)	NG02-011
MONTANA-DAKOTA UTILITIES CO. FOR	)	
AUTHORITY TO INCREASE RATES FOR	)	
NATURAL GAS SERVICE	)	

MDU'S THIRD REQUEST FOR CONFIDENTIAL
TREATMENT OF INFORMATION

Pursuant to ARSD 20:10:01:41, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) files the following information with the Commission requesting confidential treatment:

1. Exhibit No. _____ (AJF-3) accompanies the rebuttal testimony of Alvin J. Feist, Tax Planning Director of MDU Resources Group, Inc., and deals with an increase to the requested allowance for current income taxes. The Exhibit contains state specific income tax information, which is proprietary and confidential and as to which the company is entitled to an expectation of privacy. Exhibit No. _____ (AJF-3) is therefore prepared and presented as confidential information.

This request for confidential treatment of information is based upon the following information:

A. The foregoing numbered paragraphs constitute an identification of the documents and the general subject matter of the materials for which confidentiality is being requested.

B. The length of time for which confidentiality is being requested is until this docket and all appeals therefrom have been exhausted. Thereafter, all documents shall be destroyed or returned to the undersigned.

C. The name, address and telephone number of a person to be contacted regarding the confidentiality requests is: David A. Gerdes, May, Adam, Gerdes & Thompson, P.O. Box 160, Pierre, South Dakota, 57501-0160, (605)224-8803, attorneys for MDU.

D. The grounds upon which confidentiality is requested are that the material constitutes confidential and proprietary information owned by MDU, the release of which would be detrimental to MDU and cause irreparable injury. The release of any such

information would create a competitive disadvantage for MDU with its competitors. Further, the information is susceptible to no beneficial or legitimate business purpose to anyone other than the parties to the documents.

E. The factual basis that qualifies the information for confidentiality is that the information was requested as a part of discovery in this docket. The information serve no useful purpose except as it may relate to the issues between the parties in this docket. Any outside use of this information will be a violation of MDU's confidential rights.

WHEREFORE MDU prays that the Commission keep the accompanying information confidential under its rules, and that any person or party viewing such information may do so only under a confidentiality agreement approved by MDU or its authorized representative.

Dated this 12 day of June, 2003.

MAY, ADAM, GERDES & THOMPSON LLP

BY: _____
DAVID A. GERDES
Attorneys for MDU
503 South Pierre Street
P.O. Box 160
Pierre, South Dakota 57501-0160
Telephone: (605)224-8803
Telefax: (605)224-6289

CERTIFICATE OF SERVICE

David A. Gerdes of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 12 day of June, 2003, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, to-wit:

Karen Cremer, Staff Attorney
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, SD 57501-5070

Dave Jacobson, Staff Analyst
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, SD 57501-5070

David A. Gerdes

Bob Sahr, Chair
Gary Hanson, Vice-Chair
Jim Burg, Commissioner

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

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(605) 773-3809 fax

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June 13, 2003

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JUN 13 2003
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Ms. Pam Bonrud
Executive Director
SD Public Utilities Commission
500 East Capitol Avenue
Pierre, south Dakota 57501

RE: Motion to Continue and Reschedule the Hearing and Further Suspend Rates, NGO2-011

Dear Ms. Bonrud:

Enclosed please find a Motion to Continue and Reschedule the Hearing and Further Suspend Rates and a Certificate of Service in the above-referenced matter. Please file this at your convenience.

Sincerely,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

enc.

cc: David Jacobson
David Gerdes
Don Ball

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	))))	MOTION TO CONTINUE AND RESCHEDULE THE HEARING AND FURTHER SUSPEND RATES NG02-011

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., (MDU) and Commission Staff hereby jointly move the Commission to continue the hearing of June 23-25, 2003, scheduled in this matter and set a new hearing date. Pursuant to SDCL 49-34A-14, Commission Staff also requests that the Commission find that the proposed schedule of rates be further suspended for a time not to exceed a total of twelve months from the filing date.

This motion is based upon Commission Staff's request for data from MDU. MDU informed Staff on June 12, 2003, that the information will not be available until after June 18, 2003. As the hearing is scheduled to begin on June 23, 2003, there is not sufficient time to evaluate this information for hearing purposes. Both parties agree that the hearing should be rescheduled as soon as possible. MDU further agrees to not initiate the proposed rate increase at this time. However MDU reserves its right to commence the proposed rate increase, pursuant to SDCL 49-34A-17, at the expiration of six months from the original filing date of the rate increase upon proper notice to the Commission and the public.

WHEREFORE MDU AND STAFF pray that the Commission continue the hearing set for June 23-25, 2003, in this matter and reestablish a procedural schedule in accordance with the relative positions of the parties. Commission Staff further prays that the Commission find that the proposed schedule of rates be further suspended for a time not to exceed a total of twelve months from the filing date.

Dated at Pierre, South Dakota, this 13th day of June, 2003.

Karen E. Cremer

Karen E. Cremer
Staff Attorney
500 E. Capitol Ave.
Pierre, South Dakota 57501
Telephone: (605) 773-3201

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JUN 13 2003
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

CERTIFICATE OF SERVICE

Karen E. Cremer, Staff Attorney of the South Dakota Public Utilities Commission, hereby certifies that on the 13th day of June, 2003, she mailed by electronic mail or United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, to wit:

David A. Gerdes
May, Adam, Gerdes & Thompson LLP
503 South Pierre Street
P.O. Box 160
Pierre, SD 57501
Telefax: (605) 224-6289

Don Ball
Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501

Karen E. Cremer

Karen E. Cremer

Bob Sahr, Chair
Gary Hanson, Vice-Chair
Jim Burg, Commissioner

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

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June 16, 2003

Mr. Douglas W. Schulz
Senior Attorney
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Re: In the Matter of the Application of Montana-Dakota Utilities Co. for Authority to Increase Rates for Natrual Gas Service
Docket NG02-011

Dear Mr. Schulz:

Enclosed you will find a copy of Motion to Continue and Reschedule the Hearing and Further Suspend Rates with reference to the above captioned matter.

Very truly yours,

Karen E. Cremer
Staff Attorney

Enc.

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 MOTION TO CONTINUE AND RESCHEDULE THE HEARING AND FURTHER SUSPEND RATES NG02-011**

On December 30, 2002, 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 $2,173,380 or approximately 5.8%. On January 16, 2003, the Commission suspended the proposed schedule of rates for 90 days beyond January 30, 2003. On April 1, 2003, Commission Staff recommended that the suspension of the tariff be further extended for 60 days.

At its April 1, 2003, meeting, the Commission considered this matter. MDU concurred with Staff's recommendation. The Commission voted unanimously to grant the extension sought by Commission Staff. On April 30, 2003, the Commission received MDU's motion to continue and reschedule the hearing.

At its May 6, 2003, meeting, the Commission considered this matter. MDU agreed to suspend implementing the proposed rate increase for 30 days after the June 29, 2003, expiration date. The Commission voted unanimously to grant the continuance. On May 22, 2003, the Commission received MDU's motion to extend deadline for rebuttal testimony to June 6, 2003.

At its June 3, 2003, meeting, the Commission considered this matter. The Commission voted unanimously to grant MDU's motion to extend deadline for rebuttal testimony to June 6, 2003. On June 13, 2003, the Commission received a motion to continue and reschedule the hearing and further suspend rates from MDU and Commission Staff.

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 June 17, 2003, meeting, the Commission considered this matter. The Commission voted unanimously to grant MDU's and Commission Staff's motion to continue and reschedule the hearing and further suspend rates. It is therefore

ORDERED, that MDU's and Commission Staff's motion to continue and reschedule the hearing and further suspend rates is granted.

Dated at Pierre, South Dakota, this 1st day of July, 2003.

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: 7/2/03

(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

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October 28, 2003

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

Mr. Douglas W. Schulz
Senior Attorney
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 Application of Montana-Dakota Utilities Co. for Authority to Increase Rates for Natural Gas Service
Docket NG02-011

Gentlemen:

Enclosed each of you will find copies of Joint Motion for Approval of Settlement Stipulation and Staff Memorandum Supporting Settlement Stipulation with reference to the above captioned matter. This is intended as service upon you by mail.

Very truly yours,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

cc: Mr. Robert G. Towers
Mr. Dave Peterson
Mr. Basil L. Copeland Jr.

Enc.

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OCT 27 2003
SOUTH DAKOTA PUB
UTILITIES COMMISSI

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 NG02-011

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 of the issues in this proceeding. In support of this motion, 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. NG02-011.
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. NG02-011.

Montana-Dakota Utilities Co.

BY: _____

David A. Gerdes
Attorney
May, Adam, Gerdes and Thompson
503 South Pierre Street
P.O. Box 160
Pierre, SD 57501

DATED: 10/27/03

South Dakota Public Utilities Commission

BY: Karen E. Cremer

Karen E. Cremer
Attorney
State Capitol Building
500 East Capitol Ave.
Pierre, SD 57501

DATED: 10/27/03

RECEIVED
OCT 27 2003
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. NG02-011

I. SETTLEMENT STIPULATION

On December 30, 2002, 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 $2,173,380. The Staff of the Commission ("Commission Staff") on April 22, 2003, filed its direct testimony supporting an overall increase for Montana-Dakota of $249,236. By orders dated January 16, 2003 and April 1, 2003, the Commission suspended Montana-Dakota's proposed tariff. By order issued June 17, 2003, it was agreed upon by Montana-Dakota and the Commission Staff to further suspend rates.

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. NG02-011. 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, Commission Staff would have filed rebuttal testimony responding 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 approximately $1.306 million 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 9.409%.

2. Other Conditions

It is further agreed upon by the Parties that Montana-Dakota will implement a Distribution Delivery Stabilization Mechanism (DDSM). The DDSM will adjust customer bills in each billing cycle by the difference between the customer's actual temperature-sensitive usage and the customer's calculated usage under normal weather conditions. The DDSM will apply to all Residential and Firm General Service customers beginning with the first billing cycle starting on or after November 1 of each year and ending with the May 1 billing cycle. The DDSM charge or credit will be shown as a separate line item on customer bills. Initial implementation of the DDSM is to begin on March 1, 2004.

In addition to the rate changes provided for herein, the Parties agree that, henceforth, Montana-Dakota will install, own and maintain all new and replacement service lines. Presently, Montana-Dakota's customers own and are responsible for maintenance costs of their service lines.

3. Tariffs

The Tariffs reflect the following proposed basic service charges:

Rate Class	Base Rate
Residential	$7.60
Firm General	
Meters < 500 cubic ft./hour	10.00
Meters > 500 cubic ft./hour	20.00
Air Force	95.00
Small Interruptible Sales	50.00
Small Interruptible Transport	125.00
Large Interruptible Sales	150.00
Large Interruptible Transport	200.00

4. Implementation of Rates

The revised rate schedules shall be implemented with service rendered on and after November 1, 2003, with bills prorated so that usage prior to November 1, 2003 is billed at the previous rates and usage on and after November 1, 2003, is billed at the new rates.

5. Conclusion

This Stipulation is entered into this 27th day of October, 2003.

Montana-Dakota Utilities Co.

BY: David A. Gerdes

Mr. David A. Gerdes
Attorney
May, Adam, Gerdes and Thompson
503 South Pierre Street
P.O. Box 160
Pierre, SD 57501

DATED: 10/24/03

South Dakota Public Utilities Commission

BY: Karen E. Cremer

Karen E. Cremer
Attorney
State Capitol Building
500 East Capitol Building
Pierre, SD 57501-5070

DATED: 10/27/03

Change in Natural Gas Rates

On December 30, 2002, Montana-Dakota Utilities Co. (Montana-Dakota) filed an application with the South Dakota Public Utilities Commission for an increase in prices charged for natural gas service to our customers. Montana-Dakota requested an increase of approximately $2.17 million in additional revenues. Only non-gas related or distribution costs were a part of the filing. The primary reasons for the rate filing were increases in expenses such as; operation and maintenance costs, depreciation, taxes and an increase in the investment in facilities used to provide natural gas service to customers. These increases occurred in spite of the Company's efforts to control these costs. Montana-Dakota's non-gas rates were last increased in early 1995. On _____, the South Dakota Public Utilities Commission approved a natural gas rate increase in the amount of $1,305,649.

Effective with the rate change on November 1, 2003, the South Dakota Public Utilities Commission also approved a number of changes to the rate components. The charge now referred to as the monthly "Base Rate" will be replaced with a "Basic Service Charge" to better describe the type of costs recovered through this charge. Also, the Basic Service Charge will be billed on a per day basis, rather than the former fixed monthly charge. The Commodity Charge has been separated into two components: a Distribution Delivery Charge and the Cost of Gas. The Distribution Delivery Charge is a uniform per decatherm (dk) charge representing the non-gas costs of delivering gas to our customers. The Cost of Gas component recovers Montana Dakota's gas supply costs and is subject to change on a monthly basis pursuant to the Purchased Gas Cost Adjustment.

The new Basic Service Charge and Distribution Delivery Charge became effective with service rendered on and after November 1, 2003. The first bill you receive may be prorated, depending on your meter reading date. This means that any gas used prior to November 1, 2003 will be billed at the old price, and any gas used on and after November 1, 2003 will be billed at the new rates included in this folder.

Beginning March 1, 2004 Montana-Dakota will apply a Distribution Delivery Stabilization Mechanism (DDSM) adjustment to Residential Gas Service Rate 60 and Firm General Gas Service Rate 70 customers' bills. This mechanism is designed to offset any over- or under-collection of distribution delivery charge revenues during the period from October 1 through April 30 each year. Stated another way, during these months the usage used to bill rate 60 and rate 70 customers for the non-gas portion of their rate will be adjusted to reflect consumption at normal temperature levels instead of actual temperature levels. The effect of this adjustment is to stabilize customer billings by lowering usage levels during times of colder than normal temperatures and raising them during

times of warmer than normal temperatures. The adjustment itself is revenue neutral over time meaning on average it will not increase or decrease the overall revenues to the Company. The DDSM adjustment will be shown as an additional charge or a credit amount on your billing statement.

On November 1, 2003, the Purchased Gas Adjustment (PGA), filed monthly with the South Dakota Public Utilities Commission, decreased $0.356 per dk for residential 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 November 1, 2003.

Residential Gas Service – Rate 60
Rate:

Basic Service Charge	$0.25 per day*
Distribution Delivery Charge	$1.435 per dk*
Cost of Gas	$5.868 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	$0.33 per day*
Meters rated over 500 cubic feet per hour	$0.66 per day*
Distribution Delivery Charge	$1.078 per dk*
Cost of Gas	$5.868 per dk**

Minimum bill: Basic Service Charge

**Rates effective with service rendered on and after November 1, 2003.*
***Cost of Gas effective with service rendered on and after November 1, 2003.*

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	$28.79	$29.51	$0.72	2.50%
5	43.32	44.12	0.80	1.85%
10	79.64	80.63	0.99	1.24%
15	113.46	117.15	3.69	3.25%
18	133.75	139.06	5.31	3.97%
20	147.28	153.66	6.38	4.33%

*Residential meters under 500 cubic feet per hour.

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 11/03

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

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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

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.

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Section No. 3
Original 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	$5.868	$7.303
Ellsworth Air Force Base Rate 64	5	$95.00 per month	$0.062	$4.607	$4.669
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	$5.868	$6.946
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	12	$50.00 per month	$0.453	$5.868	$6.321
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	$6.094	$7.172
Summer Gas Usage			$1.078	$4.757	$5.835
Transportation Service	22				
Small Interruptible Rate 81		$125.00 per month			
Maximum			$0.453		
Minimum			$0.131		
Fuel Charge				$0.066	
Large Interruptible Rate 82		$200.00 per month			
Maximum			$0.177		
Minimum			$0.090		
Fuel Charge				$0.053	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	26	$150.00 per month	$0.177	$4.822	$4.999

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Docket No.: NG02-011

Montana-Dakota Utilities Co.
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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.

Date Filed: December 30, 2002 **Effective Date:**

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Gas Rate Schedule – SDPUC Volume No. 2

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.

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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.

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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.

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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.

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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.

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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.

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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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.
A Division of MDU Resources Group, Inc.
400 N 4th Street
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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.

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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.

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.

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.

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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.

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.

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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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.

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

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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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 Stations located at the Rapid City Regional Airport.

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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).

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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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.

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. 4
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	05-01-98 To 10-31-03	Rate 70	Rate

Date Filed: December 30, 2002 **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

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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.

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.

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.

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.

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.

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

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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.

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A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

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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.

INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

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.

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.

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.

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

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.

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Asst. Vice President-Regulatory Affairs

Docket No.: NG02-011

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.

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.

(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.

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.

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
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State of South Dakota
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Section No. 6
Original Sheet No. 2

NEW CUSTOMER APPLICATION CARD – GENERAL SERVICE

NEW CUSTOMER APPLICATION CARD - GENERAL SERVICE

20902(6-81) (Rev.11/87) MONTANA-DAKOTA UTILITIES CO. front

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: ___/___/___

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

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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:

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

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Section No. 6
Original Sheet No. 4

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:

H

DIRECT PAYMENTS TO
MONTANA-DAKOTA UTILITIES CO.

☐ 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 MULTIPLIER	BILLING FACTOR FOR	MULTIPLIER	USAGE KWH-MV-DK	AMOUNT

UTILITY TYPE	ADJUSTMENTS GAS - PGA ELECTRIC - PGA	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

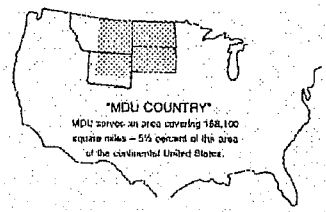
FORM NO. 20054 (11/70) REV. (10-91)

Date Filed:	December 30, 2002	**Effective Date:**	
Issued By:	Donald R. Ball Director of 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

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 5000, Bismarck, North Dakota 58506-5600.

AE - All Electric
AI - Alternate Energy Dated 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
GF - 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 - Pro-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 - Supercompressability
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:**

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Director of 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

DISCONNECT NOTICE

13 17 342

R6

MONTANA-DAKOTA UTILITIES CO

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 $26.50 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 **Effective Date:**

Issued By: Donald R. Ball
Director of Regulatory Affairs

Docket No.:

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

CUSTOMER INFORMATION BOOKLET

CUSTOMER INFORMATION BOOKLET

ADDITIONAL CUSTOMER INFORMATION FOR SOUTH DAKOTA CUSTOMERS

Montana-Dakota Utilities Co 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 public utilities in the state.*

MDU 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. In most cases, the problem will be solved with a visit or phone call to your nearest MDU office. Our employees are trained to help you.

MDU will make a full and prompt investigation of all written complaints received. Please address all written complaints to the manager at your nearest MDU office. The address of your local MDU office appears on your utility bill or it is listed in your local *telephone directory.*

DISPUTES

Whenever a customer advises MDU, before the disconnection of natural gas or electric service, that any part of the billing, charges or service is in dispute, MDU 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 MDU must notify the customer that the customer has the privilege 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
1-800-332-1782

CREDIT AND DEPOSIT POLICIES

MDU'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.

MDU will not require a deposit or guarantee from any new or present *customers who have* established good credit. MDU 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 any utility 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 MDU.

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 MDU's rules on file with the *South Dakota Public Utilities Commission.* These rules are available for your inspection for electric customers at the Mobridge MDU office and for natural gas customers at the Rapid City MDU office.
4. You have broken the terms of the contract for service with MDU or have failed to furnish those things necessary to obtain utility service.
5. You have failed to allow MDU employees access to company equipment located on your premises for meter reading, inspection, maintenance, replacement of equipment or to conduct investigations for hazardous conditions.
6. Unauthorized use of MDU's equipment or tampering with *MDU'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 *MDU* 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 (20) 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. MDU 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 MDU 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 MDU's business offices are not open to the public.

The customer can pay a delinquent bill at the last minute to avoid disconnection. MDU'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, MDU 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. MDU 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. MDU shall not disconnect residential utility service from Nov. 1 to March 31 without adding an additional 30 days to the normal disconnection date. *MDU 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, *MDU 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

MDU 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 MDU in an attempt to force payment of that bill, except when that person, even though not personally liable to MDU, 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 MDU's customer rules. A complete listing of MDU customer rules and South Dakota Public Utilities Commission rules, regulations and rate schedules are available for your inspection at the Mobridge MDU office for electric customers and the Rapid City MDU office for natural gas customers. Your billing, payment and deposit records are also available to you for inspection. MDU will furnish additional information as you may reasonably request.

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

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

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.

20292(11-80)
(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: _____

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

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:**

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

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

20511(9-76)
(Rev. 12/86)

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

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

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

204[illegible]
Rev. [illegible]

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:**

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

Docket No.: NG02-011

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)

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)

30877(12-82)
(Rev. 4/98)

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 _____ 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 _____, _____ 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

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 _____ between Montana-Dakota Utilities Co. and _____ covering natural gas service to its 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____.

By: _____
(Gas Supply Department)

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 G4, Interruptible General Gas Transportation Service Rate G1, or Interruptible Industrial Gas Transportation Service Rate G2, 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 material.

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

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)

CUSTOMERS AGREEMENT FOR GAS EXTENSION

21417(12-91)
(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

CUSTOMERS AGREEMENT FOR GAS EXTENSION

21457(12-91)
(Rev. 11/98)

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

GAS SERVICE ORDER

GAS SERVICE ORDER (Form 20527 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 / BID
____ 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 (0380) (May require signed merchandise order)		
____ Related charges		$_____

☐ Residential ☐ New Construction ☐ Billing in Fall
☐ 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 (.2882____) 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:_____

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

GAS SERVICE ORDER

GAS SERVICE ORDER (Form 20927 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.
DATE G.D. MAPPED & BY WHOM			DATE INST. 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:
WELDER/FUSER:	LENGTH OF TEST:	TESTED BY:		PRESSURE TESTED TO: PSIG
INTERNAL COND. OF PIPE IF RETIRED: __NA __WET __DRY __FAIR __POOR	EXTERNAL COND. OF PIPE IF BARE: __NA __GOOD __FAIR __POOR		TYPE OF COATING: __NA __MW __KTRU __OTHER	CONDITION OF COATING IF COATED: __NA __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.8380_____._____W Vintage_____
Retire _____B_____30R.03PU.8376_____._____W Vintage_____

Other _____B_____30___.03PU._____._____W
Other _____B_____30___.03PU._____._____W

ITEM	SIZE	MAIN	STUB	SERV	ITEM	SIZE	MAIN	STUB	SERV
ANODE-MAG-					TEE-PL-BUTT-				
CAP-DR-					TEE-PL-BUTT-				
CAP-PL-BUTT-					TEE-PL-TAP-				
CAP-PL-BUTT-					TEE-PL-SKT-				
CAP-PL-SKT-					TEE-PL-SKT-				
CAP-PL-SKT-					TEE-PL-HVT-				
CAP-WLD-					TEE-ST-ELF-				
COATING-TC-20					TEE-STPTRN-				
COUP-PL-					TEE-STP-				
COUP-PL-					TEE-SVC-H17500-				
COUP-PL-BUTT-					TEE-TAB-MU-				
COUP-PL-BUTT-					TEE-TS-MU-				
COUP-PL-ELF-					TEE-WLD-				
COUP-PL-ELF-					TRNS-PK-				
DI-BU-WI-SPL					VLV-SLW- -INS				
ELL-PL-90-									
ELL-PL-90-SKT-									
ELL-PL-90-SKT-					ITEM	ITEM NO.	MAIN	STUB	SERV
ELL-PL-45-BUTT-					EXEMPT MATERIAL	3999998			
ELL-PL-45-BUTT-					EXEMPT MATERIAL	3999999			
ELL-PL-90-BUTT-					WI-LOC-GU#14-HMWPE	2579007			
ELL-PL-90-BUTT-					SMALL FITTINGS	2999991			
ELL-WLD-45-									
ELL-WLD-90-									
ELL-WLD-90LR-									
EFV-PL-									
LSF-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					WASTE MATERIAL				
RIS-36V-									
SLV-PL-S									

Date Filed: December 30, 2002 **Effective Date:**

Issued By: Donald R. Ball
Director of Regulatory Affairs

Docket No.:

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.
A Division of MDU Resources Group, Inc.

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: _____

RECEIVED

OCT 27 2003

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF
MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY
TO INCREASE RATES FOR NATURAL GAS SERVICE

STAFF MEMORANDUM SUPPORTING
SETTLEMENT STIPULATION

DOCKET NG02-011

Staff submits this memorandum in support of the settlement Stipulation filed October 27, 2003, by Staff and Montana-Dakota Utilities Co. (collectively, "the parties") in the above captioned matter.

BACKGROUND

On December 30, 2002, Montana-Dakota Utilities Co. (MDU) filed for approval to increase rates for natural gas service in its Black Hills service territory by $2,173,380. MDU's proposed increase was based on a projected test year ended December 31, 2003 and a return on common equity of 12%. MDU witnesses submitted testimony stating that the increase was necessary because of increases in operating expenses (operation and maintenance costs, depreciation and taxes other than income) and an increase in the investment in facilities used to provide natural gas service to Black Hills system customers.

On January 2, 2003, the Commission gave notice of the application and the intervention deadline of February 7, 2003. By Orders dated January 28th, 2003, and April 8, 2003, the Commission suspended the proposed rates in this matter. By Order dated March 20, 2003, the Commission set a procedural schedule for this application and Commission Staff filed its direct testimony on April 22, 2003. On April 30, 2003, MDU filed a motion to continue and reschedule the hearing in this matter which was granted during a Commission meeting held May 6, 2003. By Order dated June 5, 2003, a new hearing date was set. On May 22, 2003, MDU filed a motion to extend the deadline for its rebuttal testimony which was granted by Order dated June 10, 2003. On June 6, 2003, MDU filed its rebuttal testimony electronically. On June 13, 2003, MDU and Commission Staff jointly filed a motion to again reschedule the hearing and further suspend MDU's proposed rates which was granted by Commission Order dated July 1, 2003. On May 29, 2003, 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 tentative settlement of all of their outstanding differences.

On October 27, 2003, 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 projected test year ending December 31, 2003, a claimed 10.303% overall rate of return reflecting a 12% return on common equity capital based on 2003 projections and distribution of the rate increase guided by a class cost of service study. Staff's testimony, submitted after comprehensive analysis of the filing and substantial discovery, was based on the historical test year ended June 30, 2002, updated for known and measurable changes; a 9.243% rate of return based on a return on common equity of 9.75% and a distribution of the rate increase based on an independent class cost of service study.

During the time that has elapsed since testimony was filed, Staff requested, and MDU has 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. Likewise, MDU also served discovery on Staff and after further analysis has modified certain positions it established in its prefiled testimony for settlement purposes. Initially MDU requested an overall rate increase of $2,173,380 or approximately 6.9% of Staff's 6/30/02 adjusted test year revenues (5.8% of MDU's projected 2003 revenues). Staff's direct testimony explained that its analysis, with the information that existed at that time, supported an increase in MDU's rates of only $249,236 or approximately 0.8% of 6/30/02 Staff adjusted test year revenues. Reflecting the substantial additional information obtained since the filing of Staff's testimony, the settlement would allow for an increase in rates of $1,305,649 or approximately 4.14% of 6/30/02 Staff adjusted test year revenues which is approximately 60% 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 - Staff's prefiled testimony reflected test year salaried labor with an adjustment annualizing a contractual increase which had taken place 5/1/02. MDU subsequently entered into a new labor agreement which took effect 5/1/03. Staff's settlement allowance reflects the updated annualized salaried labor increase, as it has taken effect and is known and measurable. Also, Staff's prefiled testimony reflected unadjusted test year non-union labor expense. Information subsequently provided by MDU substantiated increases to non-union labor taking effect 1/1/01 and 1/1/02. These increases were annualized and included as known and measurable costs in the

Settlement. The effect of these updates is an increase in revenue requirement of approximately $297,000.

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 3/31/03. Every year, Towers Perrin performs an actuarial study for MDU which contains a current year analysis and a five year forecast. This study is received by MDU in the August/September time frame and the current study results were provided to Staff on 8/26/03. Staff incorporated the current year 2003 updated Towers Perrin amount in the settlement. Also, subsequent to Staff filing direct testimony, MDU provided updated actual medical/dental, 401k and workers compensation benefits expense as of 8/31/03. Together, these updates increased the revenue requirement of MDU by approximately $227,000.

Insurance Expense - Staff's prefiled testimony reflected test year expense updated to the 12 months ended 2/28/03. MDU subsequently provided updated expense for the 12 month period ending 5/31/03 which increased the revenue requirement by $73,000.

Rate Case Expense - Staff's proposed five year amortization was adopted and the amount spent on this case by the parties was updated, adding $15,000 to the revenue requirement, and the unamortized balance was allowed in rate base, adding an additional $7,300.

Inflation - Staff's direct testimony included an inflation adjustment for various O&M expenses using a March 2003 inflation index, which was the most current at the time of filing. During settlement, Staff agreed to update the inflation adjustment using an August 2003 inflation index. This adjustment increased Staff's revenue requirement by $4,300.

Ellsworth Air Force Base Revenue - MDU failed to include $28,600 of Gas Delivery Management Fee revenue collected from Ellsworth Air Force Base in its filed case. Recognition of this revenue decreased the revenue requirement by this same amount.

Consolidated Tax Savings - Staff's direct testimony recommended an adjustment reducing MDU's Federal income tax allowance to recognize an allocated portion of the savings enjoyed by MDU Resources Group, Inc. (of which MDU is a part) as a result of the filing of a consolidated income tax return for the affiliated group. This adjustment reduced MDU's revenue requirement by about $336,000. MDU submitted substantial rebuttal testimony on this issue discussing both the ratemaking principles involved and numerous technical issues. Giving consideration to the merits of these issues Staff agreed, for purposes of reaching a settlement of all issues and to obviate the need for

hearings and possible judicial review of this issue, to limit the tax adjustment to achieve a revenue requirement effect of one-half of the amount proposed in its filed testimony. Thus, MDU's revenue requirement is reduced by $168,000 and Staff's filed revenue requirement is increased by $168,000.

Rate Base Items

Update to Test Year Accumulated Depreciation - At the time of filing Staff's prefiled case, Staff lacked the necessary information to present a test year 13 month average balance of accumulated depreciation. During settlement discussions, MDU provided that necessary information and Staff updated its adjustment. This update to Staff's case decreased the revenue requirement by approximately $5,000.

Annualizing non-revenue producing plant - During settlement negotiations, MDU provided Staff with adequate information to modify its original adjustment to annualize both test year and post test year non-revenue producing plant additions to a more precise level. These modifications to gas plant in service, accumulated depreciation and depreciation expense increased the revenue requirement by approximately $136,000. This increase in rate base also affects Staff's Ad Valorem Tax adjustment, resulting in a $1,000 increase to Staff's revenue requirement. Additionally, the information provided by MDU also uncovered additional gains on the sale of retired plant assets. This update resulted in a $37,000 decrease to the revenue requirement in Staff's case.

Accumulated Depreciation Update - Staff's prefiled case included an adjustment to decrease depreciation expense for mains and services plant accounts. During settlement negotiations Staff agreed to update accumulated deprecation to reflect the Staff proposed depreciation rates. This update accounted for a $131,000 increase to the revenue requirement.

Error Correction - While preparing Staff's case, an encoding error was made on the depreciation adjustment. Staff reversed the sign of an adjustment amount for accumulated deprecation. Correcting this error results in a $21,500 increase in the revenue requirement.

Cost of Capital Issues

Return on Common Equity - Staff's filed evidence calculated MDU's revenue requirement using a 9.75% return on equity capital (ROE). Staff's cost of capital evidence supported an ROE in the range of 9.0% to 10.0%. The Settlement reflects an ROE of 10.075%, slightly higher than the upper end of the recommended range. This increment is justified generally in light of the parties ability to reach an overall

settlement thereby avoiding the time and cost of Commission hearings and, further, in light of MDU's agreement to proceed with its proposal to henceforth assume ownership of all new and replacement service lines. The cost of service associated with such lines that already have been built (and not otherwise recognized in the revenue requirement calculation) equal the revenues provided by the incremental return allowance of 0.075%. Moving from 9.75%to 10.075% increased revenue requirement by approximately $46,000.

Rate Design Issues

Distribution of Settlement Increase - In its initial filing, based on its determination of the relative rates of return generated from each rate class, Staff recommended that the entire approximate $250,000 rate increase, which it was then recommending, be assigned to the Firm General Service class ("FGS"). (Staff witness Towers' testimony, pp. 15-21). Montana-Dakota's filing placed 55% of its proposed $2.2 million rate increase on Residential customers with the remaining 45%, or $970,000, allocated to the FGS class. (Exhibit No. __(TAA-1). As explained elsewhere in this Memorandum, information subsequently provided by the Company caused Staff to increase its recommended rate increase to the $1.3 million level reflected in the Settlement.

The tariffs reflected in the Settlement would allocate 52% and 48% of the total increase, respectively, to the Residential and FGS classes and represent measurable movement away from Montana-Dakota's initially-proposed split (55-45), tempered by consideration of the impact of the larger-than-average increase to FGS customers.

Basic Service Charges - In its initial filing, based on an analysis of "customer costs" Staff opposed the Company's proposed increases in its fixed monthly Basic Service Charges. For example, the Company had proposed to increase its charge to most Residential customers from $7.00 to $12.77 (billed as $0.42 per day of service) while Staff's analysis identified monthly customer costs of only $6.08. Staff voiced no objection to the proposed billing of these charges on a per day basis.

In the Settlement Staff has agreed to some increase in Basic Service Charges; for example, the rate to Residential customers will increase from $7.00 per month to $0.25 per day, equivalent to $7.60 per month. The principal reason for this deviation from Staff's filed position is the Company's agreement, notwithstanding the reduction in its proposed rate increase, to proceed with its proposal to henceforth install, own and maintain gas service lines (the line from its distribution main to the gas meter on the customer's premises). At present, the costs of these lines are the customer's responsibility. Staff supports this policy change but also recognizes that the new practice will result in higher "customer costs" to be recovered through Basic Service Charges.

DDSM - In its filed case MDU proposed, as an alternative to significantly increased customer charges, a mechanism [Distribution Delivery Stabilization Mechanism, (DDSM)], which would "correct for the over and under collection of distribution delivery charges due to weather fluctuations on an annual basis." The mechanism would apply only to Residential and Firm General Service customer classes. Direct testimony presented by Staff discussed certain concerns Staff had with the proposal including the length of time between measurement of weather conditions and application of the adjustment (one year), and the possibility of the mechanism adding to customer hardship in paying bills during future periods of extreme weather. Staff also expressed concern that certain parts of MDU's Black Hills service territory may experience weather conditions which would differ from normal to a different degree than where temperature measurements were taken. In settlement negotiations, MDU offered to have the DDSM adjustment take place in real time thereby addressing Staff's concerns about the delayed implementation aspect of the original filing. Staff also performed an analysis that showed that temperature deviations from normal are relatively uniform in MDU's service area which further eased its concern.

Staff's direct testimony also referenced public reaction to a similar proposal considered in Docket NG92-003, sponsored at that time by Minnegasco. Although Staff remains concerned about negative customer reaction to a new adjustment mechanism affecting customer billings, we also understand that natural gas price volatility has increased dramatically since the Minnegasco docket was considered. While MDU has proposed the mechanism as a revenue stability measure, customer billings are also stabilized in the same manner. While the mechanism does not affect costs recovered through the purchased gas adjustment, it does assess customers the distribution delivery charge based on weather normalized volumes as opposed to actual volumes (during the months of October through April). Although billed volumes will be higher than actual volumes when weather is warmer than normal , they will also be lower than actual volumes when weather is colder than normal. Staff found that many jurisdictions have such mechanisms in place and have been accepted by customers. In the event of severe negative reaction by customers, Staff believes that it could petition the Commission to terminate the mechanism at any time or that the Commission itself could determine the mechanism to be unacceptable and terminate it at any time pursuant to SDCL 49-34A-6 and 496-34A-26.

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Revenue Requirement
Adjusted Test Year Ended June 30, 2002

Line	Description	Staff Proposed South Dakota Black Hills - Gas Adjusted Test Year
	(a)	(b)
1	Average Rate Base	$ 17,896,086
2	Adjusted Test Year Operating Income	836,443
3	Overall Rate of Return	4.674%
4	Proposed Rate of Return	9.409%
5	Required Operating Income	1,683,843
6	Income Deficiency (Excess)	847,401
7	Gross Revenue Conversion Factor	1.53846
8	Revenue Deficiency (Excess)	1,303,693
9	Gross Receipts Tax (at 0.0015)	1,956
10	**Total Revenue Deficiency (Excess)**	**1,305,649**
11	Adjusted Test Year Revenue	31,502,895
12	**Revenue Requirement**	**$ 32,808,544**

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Operating Income Statement With Pro Forma Adjustments and Revenue Adjustment
Adjusted Test Year Ended June 30, 2002

Line No.	Description	South Dakota Black Hill - Gas Test Year 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)	$ 30,893,615	$ (20,407)	$30,873,208	$1,305,649	$ 32,178,857
3	Transportation (489) (including unbilled)	453,665	-	453,665		453,665
4	Other Revenues (488, 493, 495)	147,425	28,597	176,022		176,022
5	**TOTAL OPERATING REVENUES**	**31,494,705**	**8,190**	**31,502,895**	**1,305,649**	**32,808,544**
6	OPERATING EXPENSES:					
7	Operation and Maintenance:					
8	Natural Gas (accts 728, 804, 805, 808)	21,351,949	-	21,351,949		21,351,949
9	Labor	3,594,005	319,599	3,913,604		3,913,604
10	Benefits Expense	437,498	310,124	747,622		747,622
11	Insurance Expense	118,405	106,910	225,315		225,315
12	Uncollectible Account Expense	81,448	-	81,448		81,448
13	Regulatory Commission Expense	59	26,529	26,588		26,588
14	Other Operation and Maintenance	2,031,324	(7,121)	2,024,203		2,024,203
15	Total Operation and Maintenance	27,614,688	756,041	28,370,729	-	28,370,729
16	Depreciation and Amortization	1,607,620	(88,855)	1,518,765		1,518,765
17	Gain on Sale	-	(82,100)	(82,100)		(82,100)
18	Taxes:					
19	Property Taxes	387,047	16,239	403,286		403,286
20	Payroll Taxes					
21	FICA	250,469	28,828	279,297		279,297
22	Federal Unemployment	3,933	415	4,348		4,348
23	State Unemployment	5,894	511	6,405		6,405
24	Gross Receipts Tax	62,122	(14,869)	47,253	1,956	49,209
25	Federal Income Taxes	546,059	(330,895)	215,165	456,293	671,457
26	Deferred Income Taxes	(107,226)	-	(107,226)		(107,226)
27	Investment Tax Credit	-	-	-		-
28	Other Taxes	10,531	-	10,531		10,531
29	Total Taxes	1,158,829	(299,771)	859,059	458,249	1,317,307
30	**TOTAL OPERATING EXPENSES**	**30,381,137**	**285,316**	**30,666,453**	**458,249**	**31,124,701**
31	**OPERATING INCOME**	**$ 1,113,568**	**$ (277,126)**	**$ 836,443**	**$ 847,401**	**$ 1,683,843**
32	Rate Base	14,430,684.00		$17,896,086		$ 17,896,086
33	Rate of Return	7.717%		4.674%		9.409%
34	Staff Proposed Rate of Return			9.409%		9.409%

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Operating Income Statement With Pro Forma Adjustments
Adjusted Test Year Ended June 30, 2002

Line No.	Description	South Dakota Black Hills - Gas Test Year Per Books	Postage Expense	Interest Synch.	Inflation Adjustment	Plant Adjustments	Ad Valorem Tax Adjustment	Weather Normalization	Labor & Payroll Tax	Benefits	Insurance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	OPERATING REVENUES:										
2	Sales (480-485) (including unbilled)	$ 30,893,615						$ (20,407)			
3	Transportation (489) (including unbilled)	453,665									
4	Other Revenues (488, 493, 495)	147,425									
5	**TOTAL OPERATING REVENUES**	**31,494,705**	-	-	-		-	**(20,407)**	-	-	-
6	OPERATING EXPENSES:										
7	Operation and Maintenance:										
8	Natural Gas (accts 804, 805, 808)	21,351,949									
9	Labor	3,594,005							319,599		
10	Benefits Expense	437,498								310,124	
11	Insurance Expense	118,405									106,910
12	Uncollectible Account Expense	81,448									
13	Regulatory Commission Expense	59									
14	Other Operation and Maintenance	2,031,324	7,761		59,697						
15	Total Operation and Maintenance	27,614,688	7,761	-	59,697	-	-	-	319,599	310,124	106,910
16	Depreciation and Amortization	1,607,620				91,323					
17	Gain on Sale	-									
18	Taxes:										
19	Property Taxes	387,047					16,239				
20	Payroll Taxes										
21	FICA	250,469	-	-	-	-	-	-	28,828	-	-
22	Federal Unemployment	3,933	-	-	-	-	-	-	415	-	-
23	State Unemployment	5,894	-	-	-	-	-	-	511	-	-
24	Gross Receipts Tax	62,122	-	-	-	-	-	(31)	-	-	-
25	Federal Income Taxes (35%)	546,059	(2,716)	(8,790)	(20,894)	(31,963)	(5,684)	(7,132)	(122,274)	(108,543)	(37,419)
26	Deferred Income Taxes	(107,226)									
27	Investment Tax Credit	-									
28	Other Taxes	10,531									
29	Total Taxes	1,158,829	(2,716)	(8,790)	(20,894)	(31,963)	10,555	(7,163)	(92,520)	(108,543)	(37,419)
30	**TOTAL OPERATING EXPENSES**	**30,381,137**	**5,045**	**(8,790)**	**38,803**	**59,360**	**10,555**	**(7,163)**	**227,079**	**201,581**	**69,491**
31	**OPERATING INCOME**	**$ 1,113,568**	**$ (5,045)**	**$ 8,790**	**$ (38,803)**	**$ (59,360)**	**$ (10,555)**	**$ (13,244)**	**$ (227,079)**	**$ (201,581)**	**$ (69,491)**

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Operating Income Statement With Pro Forma Adjustments
Adjusted Test Year Ended June 30, 2002

Line No.	Description	Bonus/ SISP	Federal Income Tax Adjustment	Industry Association Dues	Institutional/ Promotional/ Goodwill Advertising	Economic Development	Rate Case Expense	Depreciation Adjustment	Gross Rcpt Tax	Gain on Sale of Plant Assets
	(a)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
1	OPERATING REVENUES:									
2	Sales (480-485) (including unbilled)									
3	Transportation (489) (including unbilled)									
4	Other Revenues (488, 493, 495)									
5	**TOTAL OPERATING REVENUES**	-	-	-	-	-	-	-	-	-
6	OPERATING EXPENSES:									
7	Operation and Maintenance:									
8	Natural Gas (accts 804, 805, 808)									
9	Labor									
10	Benefits Expense	0								
11	Insurance Expense									
12	Uncollectible Account Expense									
13	Regulatory Commission Expense						26,529			
14	Other Operation and Maintenance			(33,453)	(39,197)	(1,929)				
15	Total Operation and Maintenance	-	-	(33,453)	(39,197)	(1,929)	26,529	-	-	-
16	Depreciation and Amortization							(180,178)		
17	Gain on Sale									(82,100)
18	Taxes:									
19	Property Taxes									
20	Payroll Taxes									
21	FICA	-	-	-	-	-	-	-	-	-
22	Federal Unemployment	-	-	-	-	-	-	-	-	-
23	State Unemployment	-	-	-	-	-	-	-	-	-
24	Gross Receipts Tax	-	-	-	-	-	-	-	(14,881)	-
25	Federal Income Taxes (35%)	-	(109,297)	11,709	13,719	675	(9,285)	63,062	5,208	28,735
26	Deferred Income Taxes									
27	Investment Tax Credit									
28	Other Taxes									
29	Total Taxes	-	(109,297)	11,709	13,719	675	(9,285)	63,062	(9,673)	28,735
30	**TOTAL OPERATING EXPENSES**	-	(109,297)	(21,744)	(25,478)	(1,254)	17,244	(117,116)	(9,673)	(53,365)
31	**OPERATING INCOME**	$ -	$ 109,297	$ 21,744	$ 25,478	$ 1,254	$ (17,244)	$ 117,116	$ 9,673	$ 53,365

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Gas Operating Income Statement With Pro Forma Adjustments
Adjusted Test Year Ended June 30, 2002

Line No.	Description	Ellsworth AFB Mgnt. Fee			Total Staff Adjustments	Adjusted Test Year
	(a)	(u)	(v)	(w)	(x)	(y)
1	OPERATING REVENUES:					
2	Sales (480-485) (including unbilled)				$ (20,407)	$ 30,873,208
3	Transportation (489) (including unbilled)				-	453,665
4	Other Revenues (488, 493, 495)	28,597			28,597	176,022
5	**TOTAL OPERATING REVENUES**	**28,597**	-	-	**8,190**	**31,502,895**
6	OPERATING EXPENSES:					
7	Operation and Maintenance:					
8	Natural Gas (accts 804, 805, 808)				-	21,351,949
9	Labor				319,599	3,913,604
10	Benefits Expense				310,124	747,622
11	Insurance Expense				106,910	225,315
12	Uncollectible Account Expense				-	81,448
13	Regulatory Commission Expense				26,529	26,588
14	Other Operation and Maintenance				(7,121)	2,024,203
15	Total Operation and Maintenance	-	-	-	756,041	28,370,729
16	Depreciation and Amortization				(88,855)	1,518,765
17	Gain on Sale				(82,100)	(82,100)
18	Taxes:					
19	Property Taxes				16,239	403,286
20	Payroll Taxes					
21	FICA	-	-	-	28,828	279,297
22	Federal Unemployment	-	-	-	415	4,348
23	State Unemployment	-	-	-	511	6,405
24	Gross Receipts Tax	43	-	-	(14,869)	47,253
25	Federal Income Taxes (35%)	9,994	-	-	(330,895)	215,165
26	Deferred Income Taxes				-	(107,226)
27	Investment Tax Credit				-	-
28	Other Taxes				-	10,531
29	Total Taxes	10,037	-	-	(299,771)	859,059
30	**TOTAL OPERATING EXPENSES**	**10,037**	-	-	**285,316**	**30,666,453**
31	**OPERATING INCOME**	**$ 18,560**	**$ -**	**$ -**	**$ (277,126)**	**$ 836,443**

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Average Rate Base with Pro Forma Adjustments
Adjusted Test Year Ending June 30, 2002

Line No.	Description	South Dakota Black Hills - Gas Test Year Average Per Books	Total Staff Adjustments	Total Staff Adjusted Rate Base
	(a)	(b)	(c)	(d)
1	Gas Plant in Service (101)			
2	Distribution (including Intangible - 303)	$ 29,566,276	$ -	$ 29,566,276
3	General (including Intangible - 303)	6,275,400	2,239,528	8,514,928
4	Common (including Intangible 303)	2,077,553	-	2,077,553
5	Total Gas Plant in Service (101)	37,919,229	2,239,528	40,158,757
6	Gas - Completed Construction Not Classified (106)	1,256,966	-	1,256,966
7	Total Plant in Service (101 and 106)	39,176,195	2,239,528	41,415,723
8	Accumulated Depreciation			
9	Distribution (including Intangible)	19,614,550	(1,179,240)	18,435,310
10	General (including Intangible)	2,482,451	(491,550)	1,990,901
11	Common (including Intangible)	823,238	-	823,238
12	Total Accumulated Depreciation	22,920,239	(1,670,790)	21,249,449
13	TOTAL NET GAS PLANT IN SERVICE	16,255,956	3,910,318	20,166,274
14	Additions to Rate Base:			
15	Material and Supplies	247,865	6,209	254,074
16	Fuel Stocks	-	-	-
17	Prepayments	51,443	(3,496)	47,947
18	Advanced Tax Collection	-	(79,484)	(79,484)
19	Working Capital	-	(327,470)	(327,470)
20	Other	174,494	52,055	226,549
21	TOTAL ADDITIONS TO RATE BASE	473,802	(352,186)	121,616
22	Deductions to Rate Base:			
23	Accumulated Deferred Income Taxes	1,842,858	-	1,842,858
24	Accumulated Investment Tax Credit	39,527	88,219	127,746
25	Customer Advances for Construction	85,591	4,511	90,102
26	Customer Deposits	131,122	-	131,122
27	Accumulated Provision for Uncollectibles	52,168	-	52,168
28	Accumulated Provision for Injuries and Damages	147,808	-	147,808
29	Miscellaneous Operating Provisions	-	-	-
30	Other	-	-	-
31	TOTAL DEDUCTIONS TO RATE BASE	2,299,074	92,730	2,391,804
32	**TOTAL RATE BASE**	**$ 14,430,684**	**$ 3,465,402**	**$ 17,896,086**

Montana-Dakota Utilities Co.
Docket NG02-011
South Dakota Average Rate Base with Pro Forma Adjustments
Adjusted Test Year Ending June 30, 2002

Line No.	Description	South Dakota Black Hills - Gas Test Year Average Per Books	Plant Adjustments	Depreciation Adjustment	Updates	Working Capital	Investment Tax Credit	Unamortized Rate Case Expense	Total Staff Adjustments	Total Staff Adjusted Rate Base
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Gas Plant in Service (101)									
2	Distribution (including Intangible - 303)	$ 29,566,276							-	$ 29,566,276
3	General (including Intangible - 303)	6,275,400	2,239,528						2,239,528	8,514,928
4	Common (including Intangible 303)	2,077,553							-	2,077,553
5	Total Gas Plant in Service (101)	37,919,229	2,239,528	-	-	-	-	-	2,239,528	40,158,757
6	Gas - Completed Construction Not Classified (106)	1,256,966							-	1,256,966
7	Total Gas Plant in Service (101 and 106)	39,176,195	2,239,528	-	-	-	-	-	2,239,528	41,415,723
8	Accumulated Depreciation									
9	Distribution (including Intangible)	19,614,550		(1,179,240)					(1,179,240)	18,435,310
10	General (including Intangible)	2,482,451	(491,550)						(491,550)	1,990,901
11	Common (including Intangible)	823,238							-	823,238
12	Total Accumulated Depreciation	22,920,239	(491,550)	(1,179,240)	-	-	-	-	(1,670,790)	21,249,449
13	TOTAL NET GAS PLANT IN SERVICE	16,255,956	2,731,078	1,179,240	-	-	-	-	3,910,318	20,166,274
14	Additions to Rate Base:									
15	Material and Supplies	247,865			6,209				6,209	254,074
16	Fuel Stocks	-							-	-
17	Prepayments	51,443			(3,496)				(3,496)	47,947
18	Advanced Tax Collection	-				(79,484)			(79,484)	(79,484)
19	Working Capital	-				(327,470)			(327,470)	(327,470)
20	Other	174,494			(9,253)			61,308	52,055	226,549
21	TOTAL ADDITIONS TO RATE BASE	473,802	-	-	(6,540)	(406,954)	-	61,308	(352,186)	121,616
22	Deductions to Rate Base:									
23	Accumulated Deferred Income Taxes	1,842,858							-	1,842,858
24	Accumulated Investment Tax Credit	39,527					88,219		88,219	127,746
25	Customer Advances for Construction	85,591			4,511				4,511	90,102
26	Customer Deposits	131,122							-	131,122
27	Accumulated Provision for Uncollectibles	52,168							-	52,168
28	Accumulated Provision for Injuries and Damages	147,808							-	147,808
29	Miscellaneous Operating Provisions	-							-	-
30	Other	-							-	-
31	TOTAL DEDUCTIONS TO RATE BASE	2,299,074	-	-	4,511	-	88,219	-	92,730	2,391,804
32	**TOTAL RATE BASE**	**$ 14,430,684**	**2,731,078**	**1,179,240**	**(11,051)**	**(406,954)**	**(88,219)**	**61,308**	**3,465,402**	**$ 17,896,086**

Montana-Dakota Utilities Co.
Docket NG02-011
Proposed Capital Structure and Rate of Return
Adjusted Test Year Ending June 30, 2002

Line No.	**Source**	**% of Total**	**Cost Rate**	**Weighted Cost**
	(a)	(b)	(c)	(d)
1	Long Term Debt	43.441%	9.211%	4.001%
2	Preferred Stock	5.330%	4.624%	0.246%
3	Common Equity	51.229%	10.075%	5.161%
4	Total	100.000%		9.409%

Montana-Dakota Utilities Co.
Docket NG02-011
Interest Synchonization Adjustment
Adjusted Test Year Ended June 30, 2002

Line	**Description** (a)	**Amount** (b)	
1	Average Rate Base	$ 17,896,086	
2	CWIP (not included in rate base)	-	1986 tax law change
3	Investment To Be Financed	17,896,086	
4	Weighted Cost of Debt	4.001%	
5	Synchronized Interest Expense	716,085	
6	Interest Expense as filed	690,972	
7	Difference In Interest Expense	25,113	
8	Federal Income Tax Adjustment (35%)	**$ (8,790)**	

Montana-Dakota Utilities Co.
Docket NG02-011
Cash Working Capital
Adjusted Test Year Ended June 30, 2002

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	$ 21,351,949	$ -	$ 21,351,949	$ 58,498	41.2	$ 2,410,118
2	Labor Expense	3,594,005	319,599	3,913,604	10,722	19	203,718
3	Fringe Benefit	437,498	310,124	747,622	2,048	27.7	56,730
4	Insurance Expense	118,405	106,910	225,315	N/A		
5	Uncollectible Accounts Exp.	81,448	-	81,448	223	230.6	51,424
6	Regulatory Commission Exp.	59	26,529	26,588	N/A		
7	Other O & M Expense	2,031,324	(7,121)	2,024,203	5,546	16.4	90,954
8	Total O & M	27,614,688	756,041	28,370,729	77,037		2,721,990
9	Depreciation & Amortization	1,607,620	(88,855)	1,518,765	4,161	0	-
10	Deferred Income Taxes	(107,226)	-	(107,226)	(294)	0	-
11	Ad Valorem Tax	387,047	16,239	403,286	1,105	395.25	436,751
12	Payroll - FICA	250,469	28,828	279,297	765	19	14,535
13	Payroll - FUTA	3,933	415	4,348	12	47	564
14	Payroll - SUTA	5,894	511	6,405	18	47	846
15	S D Gross Receipts Tax	62,122	(12,913)	49,209	135	334	45,090
16	Federal Income Tax	546,059	125,398	671,457	1,840	37	68,080
17	Interest on Long Term Debt	690,972	25,113	716,085	1,962	91.3	179,131
18	Preferred Stock Dividends			44,107	121	45.6	5,518
19	Total	$ 31,061,578	$ 850,777	$ 31,956,462	$ 86,862	39.98	$ 3,472,505.00

20	Revenue Lag Days	36.21
21	Expense Lead Days	39.98
22	Net Days	(3.77)
23	Expense per Day	86,862
24	**Cash Working Capital**	**(327,470)**

Montana-Dakota Utilities Co.
Docket NG02-011
Tax Collections Available
Adjusted Test Year Ended June 30, 2002

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	$ 250,469	$ 28,828	$ 279,297.00	$ 765.20	19	$ 14,538.75
2	Federal Witholding	407,368	36,225	443,593.00	$ 1,215.32	19	$ 23,091.14
3	South Dakota Sales Tax	1,537,115	52,553.56	1,589,668.56	$ 4,355.26	9.61	$ 41,854.01
4	**Total**						**$ 79,483.90**

MONTANA-DAKOTA UTILITIES
REVENUE INCREASE
COMPARISON

LINE NO.	REVENUE INCREASE by CUSTOMER CLASS	Dekatherms	Dekatherms	Test Year Revenue	Proposed Revenue	Revenue (Inc./Dec.)	Percent (Inc./Dec.)
1	RESIDENTIAL	3,085,321	3,085,321	$6,937,382	$7,619,232	$681,850	9.8%
2	FIRM GENERAL SERVICE	2,120,154	2,120,154	2,386,988	3,010,344	623,356	26.1%
3	FIRM CONTRACT SERVICE	625,741	625,741	219,558	219,558	0	0.0%
4	ELLSWORTH AIR FORCE BASE	577,549	577,549	36,948	36,948	0	0.0%
5	MISC. INTERRUPTIBLE TRANSPORT & OTHER REVENUES	1,327,974	1,327,974	446,133	446,321	188	0.0%
6	TOTAL	7,736,740	7,736,740	$10,027,010	$11,332,403	$1,305,393	13.0%

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	$7.00	$7.60
2	FIRST 10 DEKATHERMS	$1.39600	$1.43500
3	EXCESS DEKATHERMS	$0.89600	$1.43500
4	PGA	$4.99500	$4.99500

Rate 600 **SMALL METER RESIDENTIAL**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
5	0	$7.00	$7.60	$0.60	8.63%
6	1	13.39	14.03	0.64	4.80%
7	2	19.78	20.46	0.68	3.45%
8	3	26.17	26.89	0.72	2.76%
9	4	32.56	33.32	0.76	2.33%
10	5	38.96	39.75	0.80	2.05%
11	6	45.35	46.18	0.84	1.85%
12	7	51.74	52.61	0.88	1.70%
13	8	58.13	59.04	0.92	1.58%
14	9	64.52	65.47	0.96	1.48%
15	10	70.91	71.90	0.99	1.40%
16	12	82.69	84.76	2.07	2.51%
17	15	100.37	104.05	3.69	3.68%
18	20	129.82	136.20	6.38	4.92%
19	25	159.28	168.35	9.08	5.70%
20	30	188.73	200.50	11.77	6.24%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	ROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	15	$ 100.37	$ 104.05	$ 3.69	3.7%
FEB	11	76.80	78.33	1.53	2.0%
MAR	11	76.80	78.33	1.53	2.0%
APR	7	51.74	52.61	0.88	1.7%
MAY	4	32.56	33.32	0.76	2.3%
JUN	3	26.17	26.89	0.72	2.8%
JUL	2	19.78	20.46	0.68	3.4%
AUG	2	19.78	20.46	0.68	3.4%
SEP	3	26.17	26.89	0.72	2.8%
OCT	6	45.35	46.18	0.84	1.8%
NOV	9	64.52	65.47	0.96	1.5%
DEC	13	88.58	91.19	2.61	2.9%
TOTAL	86	$628.63	$644.23	$15.60	2.5%

AVERAGE MONTHLY USE = 7.2 DekaTherms

Source:
Exhibit (MCB-5)
PGA is 12 Month Average Ending 9/30/2003

Montana-Dakota Utilities
South Dakota - Gas
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LINE NO.		PRESENT	PROPOSED
21	CUSTOMER CHARGE	$7.50	$10.04
22	FIRST 15 DEKATHERMS	$1.25500	$1.07800
23	EXCESS DEKATHERMS	$0.75600	$1.07800
24	PGA	$4.99500	$4.99500

Rate 700 **SMALL METER FIRM GENERAL SERVICE**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
25	0	7.50	10.04	$2.54	33.83%
26	5	38.75	40.40	1.65	4.26%
27	10	70.00	70.77	0.77	1.10%
28	15	101.25	101.13	(0.12)	-0.12%
29	20	130.01	131.50	1.49	1.15%
30	30	187.52	192.23	4.71	2.51%
31	40	245.03	252.96	7.93	3.24%
32	50	302.54	313.69	11.15	3.69%
33	60	360.05	374.42	14.37	3.99%
34	70	417.56	435.15	17.59	4.21%
35	80	475.07	495.88	20.81	4.38%
36	90	532.58	556.61	24.03	4.51%
37	100	590.09	617.34	27.25	4.62%
38	150	877.64	920.99	43.35	4.94%
39	200	1,165.19	1,224.64	59.45	5.10%
40	250	1,452.74	1,528.29	75.55	5.20%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	ROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	51	$ 308.29	$ 319.76	$ 11.47	3.7%
FEB	39	239.27	246.88	7.61	3.2%
MAR	39	239.27	246.88	7.61	3.2%
APR	24	153.01	155.79	2.78	1.8%
MAY	15	101.25	101.13	(0.12)	-0.1%
JUN	9	63.75	64.69	0.94	1.5%
JUL	6	45.00	46.48	1.48	3.3%
AUG	6	45.00	46.48	1.48	3.3%
SEP	12	82.50	82.91	0.41	0.5%
OCT	21	135.76	137.57	1.81	1.3%
NOV	33	204.77	210.45	5.68	2.8%
DEC	45	273.78	283.32	9.54	3.5%
TOTAL	300	$1,891.65	$1,942.35	$50.70	2.7%

41 AVERAGE MONTHLY USE = 25 DekaTherms

Source:
Exhibit (MCB-5)
PGA is 12 Month Average Ending 9/30/2003

Montana-Dakota Utilities
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LINE NO.		PRESENT	PROPOSED
42	CUSTOMER CHARGE	$14.00	$7.60
43	FIRST 10 DEKATHERMS	$1.39600	$1.43500
44	EXCESS DEKATHERMS	$0.89600	$1.43500
45	PGA	$4.99500	$4.99500

Rate 601 **LARGE METER RESIDENTIAL**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
46	0	14.00	7.60	($6.40)	-45.68%
47	5	45.96	39.75	(6.20)	-13.49%
48	10	77.91	71.90	(6.01)	-7.71%
49	15	107.37	104.05	(3.31)	-3.08%
50	20	136.82	136.20	(0.62)	-0.45%
51	30	195.73	200.50	4.77	2.44%
52	40	254.64	264.80	10.16	3.99%
53	50	313.55	329.10	15.55	4.96%
54	60	372.46	393.40	20.94	5.62%
55	70	431.37	457.70	26.33	6.10%
56	80	490.28	522.00	31.72	6.47%
57	90	549.19	586.30	37.11	6.76%
58	100	608.10	650.60	42.50	6.99%
59	150	902.65	972.10	69.45	7.69%
60	200	1,197.20	1,293.60	96.40	8.05%
61	250	1,491.75	1,615.10	123.35	8.27%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	ROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	82	$ 502.06	$ 534.86	32.80	6.5%
FEB	63	390.13	412.69	22.56	5.8%
MAR	63	390.13	412.69	22.56	5.8%
APR	39	248.75	258.37	9.63	3.9%
MAY	24	160.38	161.92	1.54	1.0%
JUN	15	107.37	104.05	(3.31)	-3.1%
JUL	10	77.91	71.90	(6.01)	-7.7%
AUG	10	77.91	71.90	(6.01)	-7.7%
SEP	19	130.93	129.77	(1.15)	-0.9%
OCT	34	219.29	226.22	6.93	3.2%
NOV	53	331.22	348.39	17.17	5.2%
DEC	73	449.04	476.99	27.95	6.2%
TOTAL	485	$3,085.14	$3,209.80	$124.67	4.0%

62 AVERAGE MONTHLY USE = 40.4 DekaTherms

Source:
Exhibit (MCB-5)
PGA is 12 Month Average Ending 9/30/2003

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LINE NO.		PRESENT	PROPOSED
63	CUSTOMER CHARGE	$15.00	$20.08
64	FIRST 15 DEKATHERMS	$1.25500	$1.07800
65	EXCESS DEKATHERMS	$0.75600	$1.07800
66	PGA	$4.99500	$4.99500

Rate 701 **LARGE METER FIRM GENERAL SERVICE**

	DEKATHERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
67	0	15.00	20.08	$5.08	33.83%
68	5	46.25	50.44	4.19	9.06%
69	10	77.50	80.81	3.31	4.26%
70	15	108.75	111.17	2.42	2.23%
71	20	137.51	141.54	4.03	2.93%
72	30	195.02	202.27	7.25	3.72%
73	40	252.53	263.00	10.47	4.15%
74	50	310.04	323.73	13.69	4.42%
75	60	367.55	384.46	16.91	4.60%
76	70	425.06	445.19	20.13	4.74%
77	80	482.57	505.92	23.35	4.84%
78	90	540.08	566.65	26.57	4.92%
79	100	597.59	627.38	29.79	4.99%
80	150	885.14	931.03	45.89	5.18%
81	200	1,172.69	1,234.68	61.99	5.29%
82	250	1,460.24	1,538.33	78.09	5.35%
83	300	1,747.79	1,841.98	94.19	5.39%
84	350	2,035.34	2,145.63	110.29	5.42%

MONTH	AVERAGE DEKATHERMS	PRESENT RATE	ROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	207	$ 1,212.94	$1,277.19	64.24	5.3%
FEB	159	936.89	985.68	48.79	5.2%
MAR	159	936.89	985.68	48.79	5.2%
APR	98	586.08	615.23	29.15	5.0%
MAY	61	373.30	390.53	17.23	4.6%
JUN	37	235.27	244.78	9.50	4.0%
JUL	25	166.26	171.90	5.64	3.4%
AUG	25	166.26	171.90	5.64	3.4%
SEP	49	304.28	317.65	13.37	4.4%
OCT	86	517.07	542.35	25.28	4.9%
NOV	135	798.87	839.93	41.06	5.1%
DEC	184	1,080.67	1,137.51	56.84	5.3%
TOTAL	1,225	$7,314.80	$7,680.33	$365.53	5.0%

85 AVERAGE MONTHLY USE = 102.1 DekaTherms

Source:
Exhibit (MCB-5)
PGA is 12 Month Average Ending 9/30/2003

Montana-Dakota Utilities
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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 $) PROPOSED	CHANGE AMOUNT
	Small Meter									
	Residential - Rate 600									
1		FIRST 10	DekaTherms	2,409,006	2,409,006	1.39600	1.43500	3,362,972	3,456,924	93,951
2		EXCESS	DekaTherms	598,351	598,351	0.89600	1.43500	536,122	858,634	322,511
3										
4							0.25	per day		
5		CUSTOMER CHARGE	BILL	419,526	419,526	7.00	7.60	2,936,682	3,190,146	253,464
6										
7	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
8		SUB TOTAL	DekaTherms	3,007,357	3,007,357			6,835,777	7,505,703	669,926
9										
10	SMR Rate Unbilled JUN 01									
11										
12		FIRST 10	DekaTherms	0	0	1.39600	1.43500	0	0	0
13		EXCESS	DekaTherms	0	0	0.89600	1.43500	0	0	0
14										
15										
16		CUSTOMER CHARGE	BILL	0	0	7.00	7.60	0	0	0
17										
18		SUB TOTAL	DekaTherms	21,176	21,176			91,089	86,371	(4,718)
19										
20	SMR Rate Weather									
21										
22		FIRST 10	DekaTherms	40,089	40,089	1.39600	1.43500	55,965	57,528	1,563
23		EXCESS	DekaTherms	9,957	9,957	0.89600	1.43500	8,922	14,289	5,367
24										
25										
26		CUSTOMER CHARGE	BILL	0	0	7.00	7.60	0	0	0
27										
28	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
29		SUB TOTAL	DekaTherms	50,047	50,047			64,886	71,817	6,930
30										
31	SMR Rate Weather - Unbilled JUN 02									
32										
33		FIRST 10	DekaTherms	0	0	1.39600	1.43500	0	0	0
34		EXCESS	DekaTherms	0	0	0.89600	1.43500	0	0	0
35										
36										
37		CUSTOMER CHARGE	BILL	0	0	7.00	7.60	0	0	0
38										
39		SUB TOTAL	DekaTherms	(1,970)	(1,970)			(66,188)	(58,810)	7,378
40										
41	**TOTAL RESIDENTIAL - RATE 600**			**3,076,610**	**3,076,610**			**$ 6,925,565**	**$ 7,605,081**	**$ 679,516**
42										

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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 $) PROPOSED	CHANGE AMOUNT
43	**Large Meter**									
44	**Residential - Rate 601**									
45										
46		FIRST 10	DekaTherms	1,903	1,903	1.39600	1.43500	2,657	2,731	74
47		EXCESS	DekaTherms	6,606	6,606	0.89600	1.43500	5,919	9,480	3,561
48										
49										
50		CUSTOMER CHARGE	BILL	217	217	14.00	7.60	3,038	1,650	(1,388)
51										
52	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
53		SUB TOTAL	DekaTherms	8,509	8,509			11,614	13,861	2,247
54										
55	LMR Rate Unbilled JUN 01									
56										
57		FIRST 10	DekaTherms	0	0	1.39600	1.43500	0	0	0
58		EXCESS	DekaTherms	0	0	0.89600	1.43500	0	0	0
59										
60										
61		CUSTOMER CHARGE	BILL	0	0	14.00	7.60	0	0	0
62										
63		SUB TOTAL	DekaTherms	76	76			217	160	(57)
64										
65	LMR Rate Weather									
66										
67		FIRST 10	DekaTherms	30	30	1.39600	1.43500	42	43	1
68		EXCESS	DekaTherms	104	104	0.89600	1.43500	93	149	56
69										
70										
71		CUSTOMER CHARGE	BILL	0	0	14.00	7.60	0	0	0
72										
73	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
74		SUB TOTAL	DekaTherms	134	134			135	192	57
75										
76	LMR Rate Weather - Unbilled JUN 02									
77										
78		FIRST 10	DekaTherms	0	0	1.39600	1.43500	0	0	0
79		EXCESS	DekaTherms	0	0	0.89600	1.43500	0	0	0
80										
81										
82		CUSTOMER CHARGE	BILL	0	0	14.00	7.60	0	0	0
83										
84		SUB TOTAL	DekaTherms	(7)	(7)			(148)	(61)	87
85										
86	**TOTAL RESIDENTIAL - RATE 601**			**8,711**	**8,711**			**$ 11,818**	**$ 14,151**	**$ 2,333**
87										
88		**TOTAL RESIDENTIAL**		**3,085,321**	**3,085,321**			**$ 6,937,382**	**$ 7,619,232**	**$ 681,850**

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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		FIRST 15	DekaTherms	279,746	279,746	1.25500	1.07800	351,081	301,566	(49,515)
2		EXCESS	DekaTherms	228,595	228,595	0.75600	1.07800	172,818	246,425	73,608
3										
4							0.33 per day			
5		CUSTOMER CHARGE	BILL	41,337	41,337	7.50	10.04	310,028	414,920	104,893
6										
7	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
8		SUB TOTAL	DekaTherms	508,341	508,341			833,927	962,912	128,985
9										
10	SMFG Rate Unbilled JUN 01									
11										
12		FIRST 15	DekaTherms	0	0	1.25500	1.07800	0	0	0
13		EXCESS	DekaTherms	0	0	0.75600	1.07800	0	0	0
14										
15										
16		CUSTOMER CHARGE	BILL	0	0	7.50	10.04	0	0	0
17										
18		SUB TOTAL	DekaTherms	2,680	2,680			13,617	13,381	(236)
19										
20	SMFG Rate Weather Normalization									
21										
22		FIRST 15	DekaTherms	3,592	3,592	1.25500	1.07800	4,508	3,872	(636)
23		EXCESS	DekaTherms	2,935	2,935	0.75600	1.07800	2,219	3,164	945
24										
25										
26		CUSTOMER CHARGE	BILL	0	0	7.50	10.04	0	0	0
27										
28	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
29		SUB TOTAL		6,527	6,527			6,726	7,036	309

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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 $) PROPOSED	CHANGE AMOUNT
30										
31	SMFG Rate Weather - Unbilled JUN 02									
32										
33		FIRST 15	DekaTherms	0	0	1.25500	1.07800	0	0	0
34		EXCESS	DekaTherms	0	0	0.75600	1.07800	0	0	0
35										
36										
37		CUSTOMER CHARGE	BILL	0	0	7.50	10.04	0	0	0
38										
39		SUB TOTAL		(242)	(242)			(11,104)	(10,753)	351
40										
41	SMFG Rate Weather - Reclassify Rate 71 and Rate 81									
42										
43		FIRST 15	DekaTherms	5,078	5,078	1.25500	1.07800	6,373	5,475	(899)
44		EXCESS	DekaTherms	4,150	4,150	0.75600	1.07800	3,137	4,474	1,336
45										
46										
47		CUSTOMER CHARGE	BILL	20	20	7.50	10.04	150	201	51
48										
49		SUB TOTAL - PER BOOKS		9,228	9,228			9,661	10,149	488
50										
41	**TOTAL FIRM GENERAL SERVICE - RATE 700**			**526,534**	**526,534**			**$ 852,826**	**$ 982,724**	**$ 129,898**
42										
43	**Lage Meter**									
44	**Firm General Service - Rate 701**									
45										
46										
47		FIRST 15	DekaTherms	193,163	193,163	1.25500	1.07800	242,420	208,230	(34,190)
48		EXCESS	DekaTherms	1,374,563	1,374,563	0.75600	1.07800	1,039,170	1,481,779	442,609
49										
50							0.66 per day			
51		CUSTOMER CHARGE	BILL	15,427	15,427	15.00	20.08	231,405	309,697	78,292
52										
53		PURCHASED GAS ADJUSTMENT				0.00000	0.00000			
54		SUB TOTAL		1,567,726	1,567,726			1,512,994	1,999,706	486,711
55										
56	LMFG Rate Unbilled JUN 01									
57										
58		FIRST 15	DekaTherms	0	0	1.25500	1.07800	0	0	0
59		EXCESS	DekaTherms	0	0	0.75600	1.07800	0	0	0
60										
61										
62		CUSTOMER CHARGE	BILL	0	0	15.00	20.08	0	0	0
63										
64		SUB TOTAL - PER BOOKS		9,672	9,672			36,647	30,022	(6,625)
65										

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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 $) PROPOSED	CHANGE AMOUNT
66	LMFG Rate Weather Normalization									
67										
68		FIRST 15	DekaTherms	2,104	2,104	1.25500	1.07800	2,641	2,268	(372)
69		EXCESS	DekaTherms	14,973	14,973	0.75600	1.07800	11,320	16,141	4,821
70										
71										
72		CUSTOMER CHARGE	BILL	0	0	15.00	20.08	0	0	0
73										
74	PURCHASED GAS ADJUSTMENT					0.00000	0.00000			
75		SUB TOTAL		17,077	17,077			13,960	18,409	4,449
76										
77	LMFG Rate Weather - Unbilled JUN 02									
78										
79		FIRST 15	DekaTherms	0	0	1.25500	1.07800	0	0	0
80		EXCESS	DekaTherms	0	0	0.75600	1.07800	0	0	0
81										
82										
83		CUSTOMER CHARGE	BILL	0	0	15.00	20.08	0	0	0
84										
85	SUB TOTAL - PER BOOKS			(854)	(854)			(29,439)	(20,518)	8,922
86										
87	**TOTAL FIRM GENERAL SERVICE - RATE 701**			**1,593,620**	**1,593,620**			**$ 1,534,162**	**$ 2,027,619**	**$ 493,457**
88										
89	**TOTAL FIRM GENERAL SERVICE**			**2,120,154**	**2,120,154**			**$ 2,386,988**	**$ 3,010,344**	**$ 623,356**

Montana-Dakota Utilities
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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 $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
	Firm Contract Service - Rate 702											
1			MIN BILLS	BILL			150.00	150.00				
2			MIN BILLS									
3			ALL	DekaTherms	623,061	623,061	0.34800	0.34800	216,825	216,825	0	
4												
5			CUSTOMER CHARGE & MINNUM	BILL	12	12	150.00	150.00	1,800	1,800	0	
6												
7			PURCHASED GAS ADJUSTMENT				0.00000	0.00000	0	0	0	
8			SUBTOTAL	DekaTherms	623,061	623,061			218,625	218,625	0	
9												
10	Firm Contract Service - Rate 702 - Weather											
11												
12			MIN BILLS	BILL			150.00	150.00				
13			MIN BILLS									
14			ALL	DekaTherms	2,680	2,680	0.34800	0.34800	933	933	0	
15												
16			CUSTOMER CHARGE & MINNUM	BILL	0	0	150.00	150.00	0	0	0	
17												
18			PURCHASED GAS ADJUSTMENT				0.00000	0.00000	0	0	0	
19			SUBTOTAL	DekaTherms	2,680	2,680			933	933	0	
20												
21	**TOTAL - Firm Contract Service - Rate 702**				**625,741**	**625,741**			**$ 219,558**	**$ 219,558**	**$ -**	**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 $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
23	**Ellsworth Air Force Base**										
24											
25		MIN BILLS	BILL			95.00	95.00				
26		MIN BILLS									
27		ALL	DekaTherms	573,249	573,249	0.06200	0.06200	35,541	35,541	0	
28											
29	CUSTOMER CHARGE & MINNUM		BILL	12	12	95.00	95.00	1,140	1,140	0	
30											
31	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
32		SUBTOTAL	DekaTherms	573,249	573,249			36,681	36,681	0	
33											
34	EAFB - Weather Normalization										
35											
36		MIN BILLS	BILL			95.00	95.00				
37		MIN BILLS									
38		ALL	DekaTherms	4,300	4,300	0.06200	0.06200	267	267	0	
39											
40	CUSTOMER CHARGE & MINNUM		BILL	0	0	95.00	95.00	0	0	0	
41											
42	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
43		SUBTOTAL	DekaTherms	4,300	4,300			267	267	0	
44											
45	**TOTAL - Ellsworth Air Force Base**			**577,549**	**577,549**			**$ 36,948**	**$ 36,948**	**$ -**	**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 $) PROPOSED	INCREASE AMOUNT	INCREASE PERCENT
47	**Small Interruptible - Rate 71**										
48											
49		MIN BILLS	BILL			40.00	50.00				
50		MIN BILLS									
51		ALL	DekaTherms	42,146	42,146	0.48400	0.45300	20,399	19,092	(1,307)	
52											
53	CUSTOMER CHARGE & MINNUM		BILL	151	151	40.00	50.00	6,040	7,550	1,510	
54											
55	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
56		SUBTOTAL	DekaTherms	42,146	42,146			26,439	26,642	203	
57											
58	Small Interruptible Rate Unbilled JUN 01										
59											
60		ALL THERMS	DekaTherms	0	0	0.48400	0.45300	0	0	0	
61											
62											
63	CUSTOMER CHARGE & MINNUM		BILL	0	0	40.00	50.00	0	0	0	
64											
65		SUB TOTAL	DekaTherms	145	145			915	953	38	
66											
58	Small Interruptible - Rate 71 - Weather Normalization										
59											
60		MIN BILLS	BILL			40.00	50.00				
61		MIN BILLS									
62		ALL	DekaTherms	388	388	0.48400	0.45300	188	176	(12)	
63											
64	CUSTOMER CHARGE & MINNUM		BILL	0	0	40.00	50.00	0	0	0	
65											
66	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
67		SUBTOTAL	DekaTherms	388	388			188	176	(12)	
68											
69	Small Interruptible Rate Unbilled JUN 02										
70											
71		ALL	DekaTherms	0	0	0.48400	0.45300	0	0	0	
72											
73											
74		CUSTOMER CHARGE	BILL	0	0	40.00	50.00	0	0	0	
75											
76		SUBTOTAL	DekaTherms	1,074	1,074			(555)	(616)	(61)	
77											
78	Small Interruptible - Rate 71 - Reclassify as Rate 70										
79											
80		MIN BILLS	BILL			40.00	50.00				
81		MIN BILLS									
82		ALL	DekaTherms	(7,350)	(7,350)	0.48400	0.45300	(3,558)	(3,330)	228	
83											
84	CUSTOMER CHARGE & MINNUM		BILL	(12)	(12)	40.00	50.00	(480)	(600)	(120)	
85											
86	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
87		SUBTOTAL	DekaTherms	(7,350)	(7,350)			(4,038)	(3,930)	108	
88								-913	-833	80	
89	**TOTAL - SMALL INTERRUPTIBLE - RATE 71**			**36,403**	**36,403**			**$ 22,035**	**$ 22,392**	**$ 356**	**1.6%**

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	PROPOSED	>-- RATE ($/UNIT) --< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>-- INCREASE --< AMOUNT	PERCENT
90											
91	**Large Interruptible - Rate 85**										
92											
93		MIN BILLS	BILL			150.00	150.00				
94		MIN BILLS									
95		ALL	DekaTherms	88,681	88,681	0.17700	0.17700	15,697	15,697	0	
96											
97	CUSTOMER CHARGE & MINNUM		BILL	12	12	150.00	150.00	1,800	1,800	0	
98											
99	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
100		SUBTOTAL	DekaTherms	88,681	88,681			17,497	17,497	0	
101											
102	**TOTAL - LARGE INTERRUPTIBLE - RATE 85**			**88,681**	**88,681**			**$ 17,497**	**$ 17,497**	**$ -**	**0.0%**
103											
104	**Small Interruptible Transportion - Rate 81**										
105											
106		MIN BILLS	BILL			90.00	125.00				
107		MIN BILLS									
108		ALL	DekaTherms	432,707	432,707	0.48400	0.45300	209,430	196,016	(13,414)	
109											
110	CUSTOMER CHARGE & MINNUM		BILL	377	377	90.00	125.00	33,930	47,125	13,195	
111											
112	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
113		SUBTOTAL	DekaTherms	432,707	432,707			243,360	243,141	(219)	
114											
115	Small Interruptible Transportion - Rate 81 - Weather Normalization										
116											
117		MIN BILLS	BILL			90.00	125.00				
118		MIN BILLS									
119		ALL	DekaTherms	1,789	1,789	0.48400	0.45300	866	810	(55)	
120											
121	CUSTOMER CHARGE & MINNUM		BILL	0	0	90.00	125.00	0	0	0	
122											
123	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
124		SUBTOTAL	DekaTherms	1,789	1,789			866	810	(55)	

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	PROPOSED	>-- RATE ($/UNIT) --< PRESENT	PROPOSED	>-- REVENUES (IN $) --< PRESENT	PROPOSED	>-- INCREASE --< AMOUNT	PERCENT
125											
115	Small Interruptible Transportation - Rate 81 - Cut Out of Service										
116											
117		MIN BILLS	BILL			90.00	125.00				
118		MIN BILLS									
119		ALL	DekaTherms	(156)	(156)	0.48400	0.45300	(76)	(71)	5	
120											
121	CUSTOMER CHARGE & MINNUM		BILL	(5)	(5)	90.00	125.00	(450)	(625)	(175)	
122											
123	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
124		SUBTOTAL	DekaTherms	(156)	(156)			(526)	(696)	(170)	
125											
126	Small Interruptible Transportation - Rate 81 - Reclassify as Rate 70										
127											
128		MIN BILLS	BILL			90.00	125.00				
129		MIN BILLS									
130		ALL	DekaTherms	(1,878)	(1,878)	0.48400	0.45300	(909)	(851)	58	
131											
132	CUSTOMER CHARGE & MINNUM		BILL	(12)	(12)	90.00	125.00	(1,080)	(1,500)	(420)	
133											
134	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
135		SUBTOTAL	DekaTherms	(1,878)	(1,878)			(1,989)	(2,351)	(362)	
136								-4876	-4238	638	
126	**TOTAL - SMALL INTERRUPTIBLE TRANSPORTATION - RATE 81**			**432,462**	**432,462**			**236,835**	**236,667**	**(168)**	**-0.1%**
127											
128											
129	**Large Interruptible Transportation - Rate 82**										
130											
131		MIN BILLS	BILL			200.00	200.00				
132		MIN BILLS									
133		ALL	DekaTherms	862,122	862,122	0.17700	0.17700	152,596	152,596	0	
134											
135	CUSTOMER CHARGE & MINNUM		BILL	175	175	200.00	200.00	35,000	35,000	0	
136											
137	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
138		SUBTOTAL	DekaTherms	862,122	862,122			187,596	187,596	0	
139											
140	Large Interruptible Transportation - Rate 82 - Cut Out of Service										
141											
142		MIN BILLS	BILL			200.00	200.00				
143		MIN BILLS									
144		ALL	DekaTherms	(91,693)	(91,693)	0.17700	0.17700	(16,230)	(16,230)	0	
145											
146	CUSTOMER CHARGE & MINNUM		BILL	(8)	(8)	200.00	200.00	(1,600)	(1,600)	0	
147											
148	PURCHASED GAS ADJUSTMENT					0.00000	0.00000	0	0	0	
149		SUBTOTAL	DekaTherms	(91,693)	(91,693)			(17,830)	(17,830)	0	
150											
140	**TOTAL - LARGE INTERRUPTIBLE TRANSPORTATION - RATE 82**			**770,429**	**770,429**			**$ 169,766**	**$ 169,766**	**$ -**	**0.0%**
141											
142	**TOTAL - OTHER INTERRUPTIBLE and TRANSPORTATION**			**1,327,974**	**1,327,974**			**$ 446,133**	**$ 446,321**	**$ 188**	**0.0%**

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 HEARING TO CONSIDER SETTLEMENT STIPULATION NG02-011**

On December 30, 2002, 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 $2,173,380 or approximately 5.8%. On January 16, 2003, the Commission suspended the proposed schedule of rates for 90 days beyond January 30, 2003. On April 1, 2003, Commission Staff recommended that the suspension of the tariff be further extended for 60 days.

At its April 1, 2003, meeting, the Commission considered this matter. MDU concurred with Staff's recommendation. The Commission voted unanimously to grant the extension sought by Commission Staff. On April 30, 2003, the Commission received MDU's motion to continue and reschedule the hearing.

At its May 6, 2003, meeting, the Commission considered this matter. MDU agreed to suspend implementing the proposed rate increase for 30 days after the June 29, 2003, expiration date. The Commission voted unanimously to grant the continuance. On May 22, 2003, the Commission received MDU's motion to extend deadline for rebuttal testimony to June 6, 2003.

At its June 3, 2003, meeting, the Commission considered this matter. The Commission voted unanimously to grant MDU's motion to extend deadline for rebuttal testimony to June 6, 2003. On June 13, 2003, the Commission received a motion to continue and reschedule the hearing and further suspend rates from MDU and Commission Staff.

At its June 17, 2003, meeting, the Commission considered this matter. The Commission voted unanimously to grant MDU's and Commission Staff's motion to continue and reschedule the hearing and further suspend rates.

On October 27, 2003, the Commission received a joint motion for approval of settlement stipulation and staff memorandum supporting settlement stipulation from Staff.

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.

Based on the joint motion for approval of the proposed settlement stipulation and staff memorandum supporting settlement stipulation, the Commission shall hear from the parties concerning the settlement stipulation on December 2, 2003, at 1:30 P.M., in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota.

It is therefore

ORDERED, that the Commission shall hear from the parties concerning the proposed settlement stipulation on December 2, 2003, at 1:30 P.M., in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota.

Dated at Pierre, South Dakota, this 13th day of November, 2003.

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: 11/14/03

(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

PUBLIC UTILITIES HEARING
Tuesday, December 2, 2003; 1:30 P.M.
Governors Inn, Kneip Room
Pierre, South Dakota

ASSEMBLAGE

	Person	Representing
1.	DAVE GEORGESS	MONTANA-DAKOTA
2.	Don Ball	Montana-Dakota
3.	Tamie Aberle	Montana-Dakota
4.	Rita Mulkern	Montana-Dakota
5.		
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MONTANA-DAKOTA UTILITIES CO.
DOCKET NO. NG02-011
COMPLIANCE TARIFFS

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.

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

December 4, 2003

RECEIVED
DEC 05 2003
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

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

Re: Compliance Natural Gas Rates
Docket No. NG02-011

Dear Ms. Bonrud:

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits an entire new Gas Tariff - Volume 2 reflecting the effective date of Service Rendered on and after December 2, 2003 pursuant to the Commission's Motion approving the Settlement Stipulation in the above referenced Docket. The Gas Tariff in effect prior to December 2, 2003 should be canceled in its entirety.

The original and ten (10) copies of this letter and tariffs have been provided to the South Dakota Public Utilities 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,

Tamie A. Aberle

Tamie A. Aberle
Pricing & Tariff Manager

Attachment

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

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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

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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

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

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	$5.868	$7.303
Ellsworth Air Force Base Rate 64	5	$95.00 per month	$0.062	$4.607	$4.669
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	$6.327	$8.088
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	$5.868	$6.946
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	12	$50.00 per month	$0.453	$5.868	$6.321
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	$6.094	$7.172
Summer Gas Usage			$1.078	$4.757	$5.835
Transportation Service	22				
Small Interruptible Rate 81		$125.00 per month			
Maximum			$0.453		
Minimum			$0.131		
Fuel Charge				$0.066	
Large Interruptible Rate 82		$200.00 per month			
Maximum			$0.177		
Minimum			$0.090		
Fuel Charge				$0.053	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	26	$150.00 per month	$0.177	$4.822	$4.999

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

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

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

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.

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
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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
Docket No.: NG02-011

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

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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.

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400 N 4th Street
Bismarck, ND 58501

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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.

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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.

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.

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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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.

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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.

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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.

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.

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.

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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.

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.

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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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.

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

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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Bismarck, ND 58501

State of South Dakota
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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 Stations located at the Rapid City Regional Airport.

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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).

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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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.

(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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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	05-01-98 To 10-31-03	Rate 70	Rate

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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.

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.

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.

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.

21. 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.

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
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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.

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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.

INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

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.

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.

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.

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.

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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.

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.

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.

(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.

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

CONSUMER'S DEPOSIT RECEIPT

Account

Received of:

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

NEW CUSTOMER APPLICATION CARD – GENERAL SERVICE

NEW CUSTOMER APPLICATION CARD - GENERAL SERVICE

front

209026(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: ___/___/___

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

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

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

☐ 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

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:

REMARKS:

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:

H

DIRECT PAYMENTS TO
MONTANA-DAKOTA UTILITIES CO.

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 KWH-MCF	BILLING FACTOR FOR MULTIPLIER	USAGE KWH-KW-DR	AMOUNT

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

FORM NO. 20064 (11/70) REV. (10-91)

Date Filed: December 30, 2002

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

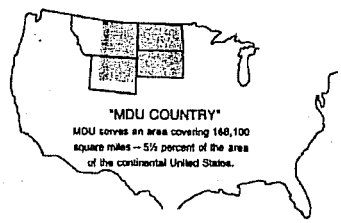
Issued By: Donald R. Ball
Director of Regulatory Affairs

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

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 - Pro-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

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Director of 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

DISCONNECT NOTICE

13 17 342

R6

MONTANA-DAKOTA UTILITIES CO

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

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

Docket No.: NG02-011

20474(7-88)
(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:

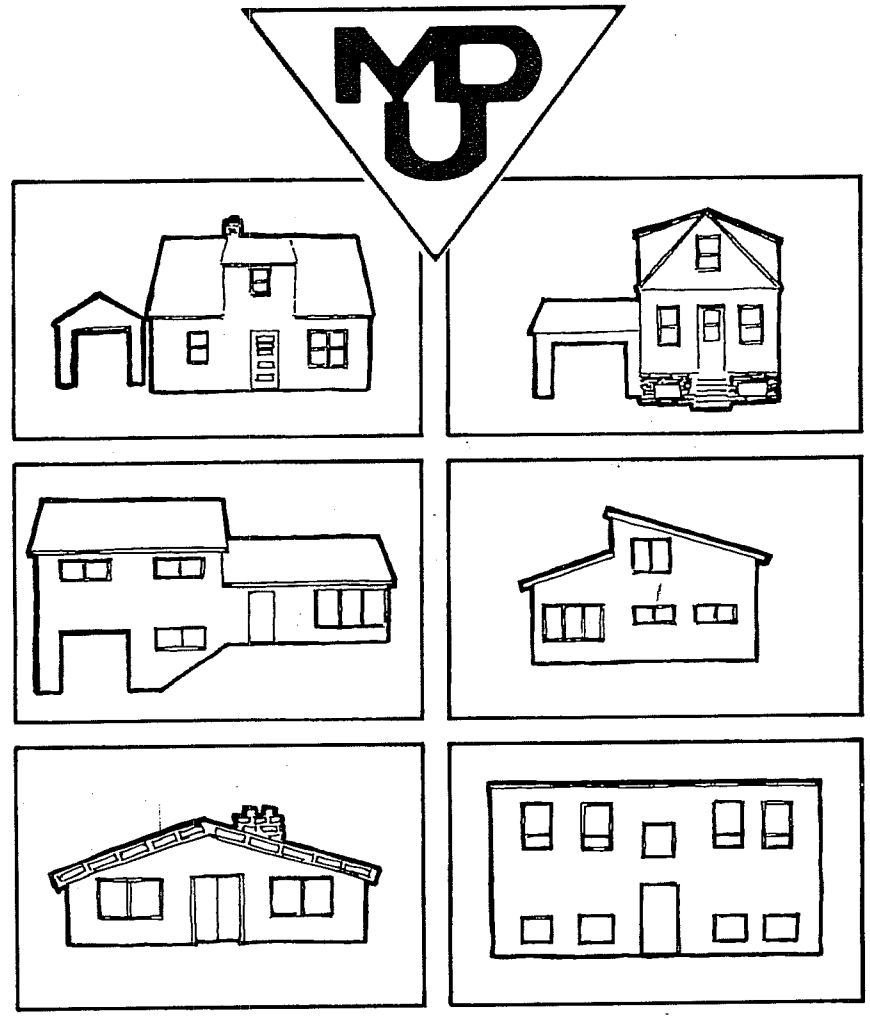
MONTANA-DAKOTA UTILITIES CO.,
A Division of MDU Resources Group, Inc.

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.

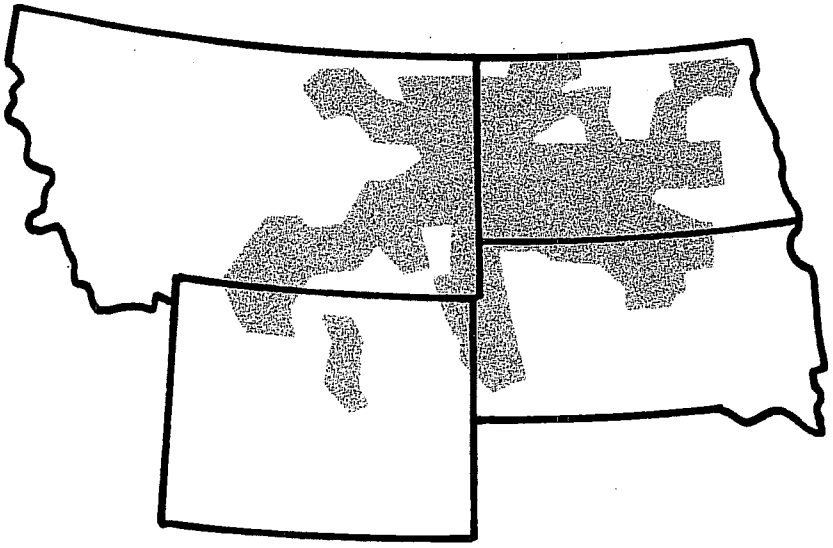
(Rev. 6/98)



CUSTOMER INFORMATION

FOR RESIDENTIAL CUSTOMERS

This is MDU Country...



"In the Community to Serve"

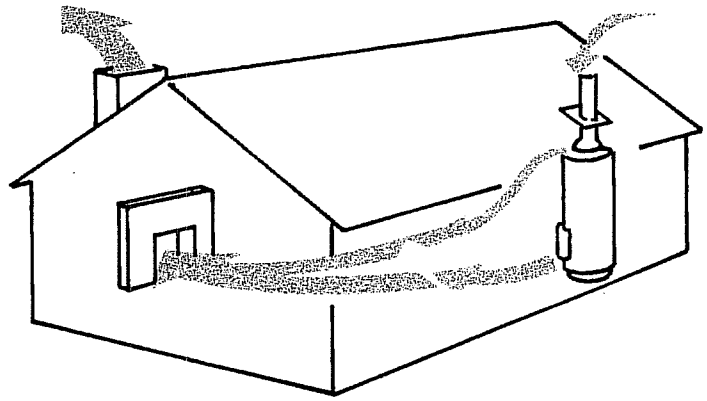
Montana-Dakota Utilities Co. didn't come about overnight. No, it's taken well over 70 years of hard work for us to grow from a small electric company serving a handful of farm communities to a large regional energy supplier. During those years of growth, we changed our name a few times and acquired a number of smaller companies and we progressed side by side with those we serve.

Today, we're a division of MDU Resources Group, Inc., a diversified energy company. We provide retail natural gas and/or electric service to parts of Montana, North Dakota, South Dakota, and Wyoming. Our service area covers over 168,000 square miles (5.5 percent of the continental USA) and we serve a population of about 550,000.

At some point in our past, we came upon a slogan – *"In the community to serve"* – and it just stuck with us. We believe in those words. Our success as a company is rooted in the growth and prosperity of our communities. We're committed to help meet tomorrow's challenges and opportunities by providing affordable, reliable energy services.

Back Drafting. In our efforts to reduce heating costs, many of us have turned to woodburning fireplaces and stoves as supplementary sources of heat along with natural gas furnaces. It's a good idea, but many homes are often too tight to provide adequate air for the safe operation of open flame heating systems (fireplaces, wood/coal stoves, natural gas furnaces, etc.). We feel that everyone should try to conserve energy. But, after you weatherize you may need to add a combustion air source to prevent back drafting.

Fireplaces require lots of air. If there is not enough air to satisfy the requirements of a fireplace or wood stove as well as a furnace or water heater all burning at the same time, the fireplace draft can pull toxic combustion products from these gas appliances back into the room. This condition can seriously endanger health. The products of combustion (which may contain carbon monoxide) must be continuously removed while the fireplace or stove is operating. In fact, any device that exhausts air from the home (including kitchen or bathroom exhaust fans) can contribute to the back drafting problem.



To Check for Back Drafting. Start a fire in the fireplace on a cold day and after a few minutes, touch the vent pipe of the furnace, water heater, or any space heater. *(Careful, they may be very hot!)* If the vent is cold, your fireplace could be creating a dangerous back draft. Turn down the thermostats and water heater temperature controls, let fireplace burn down and call a heating contractor or your local Montana-Dakota serviceman.

CAUTION: Montana-Dakota fully supports energy conservation, but we feel it is important that you know about two dangers that might result from improper energy conservation practices. We don't mean to frighten you – just inform you.

Hypothermia. Heating is the major consumer of energy in the home. To conserve energy, people turn the heat down. This is great for healthy, active people who can just put on a sweater and feel comfortable. But, young children, people confined to a bed or chair due to illness, and the elderly may be in serious danger of accidental hypothermia.

Hypothermia ("hypo" - below, and "thermia" - temperature) is the result of the body not being able to produce enough heat. It is sometimes confused with "hyperthermia" which means abnormally high temperature.

With hypothermia, the body temperature drops lower than 94° F. at a point when uncontrollable shivering begins. As the body cools further, shivering will continue until it gets to 90° F., when it reaches the danger area. Below this temperature, a life-threatening situation is present and, if left untreated, can result in death.

Here are some symptoms of hypothermia:

- Skin is pale and waxy. Face may be puffy and swollen.
- Trembling may occur, accompanied by chills, but not always.
- The person may feel warm.
- Speech slows and words become slurred.
- The person becomes forgetful.
- The person becomes very tired.

Since mental confusion is one of the first symptoms, the person is normally not aware of what is happening. **Hypothermia, even in early stages, needs immediate attention!** If you can't reach a doctor, take the person to a hospital immediately.

Remember...everyone is susceptible to hypothermia if the conditions are right. Pay particular attention to those that appear overly tired or cold.

The best solution to hypothermia, of course, is to prevent it from happening. Keep your home warm enough so additional layers of clothing or bedding will prevent the first chill. Your doctor is your best source of additional information on hypothermia.

When You Want to Contact Us...

Your local telephone company directory will give you the Montana-Dakota office address and telephone number. You will also find the address and telephone number of your nearest Montana-Dakota office on the lower portion of your utility bill.

For emergency utility service, call 1-800-MDU-FAST (1-800-638-3278).

Quick Reference

(Fill in the address and phone number of your MDU office)

MONTANA-DAKOTA UTILITIES CO.

Address: _____

Office Hours Phone Number: _____

Emergency non-office hours phone number: 1-800-MDU-FAST

Starting and Stopping Service...

We try to make it as convenient as possible for you to begin or end natural gas and/or electric service. Here are some tips that will make it easier:

- Stop in your local Montana-Dakota office and let us know the date you want service to start or stop. Please contact us as far in advance as possible.
- We might need access to your home to start or stop service. We'll make those arrangements when you contact us.
- We don't require deposits from customers who have established good credit. But, we pay interest on a deposit when one is required. The deposit will be returned to you after 12 months if you have established a prompt payment record.
- If you request that we start or stop service during working hours, there is no charge, provided that this service has not been previously requested within the past year. Outside of working hours, however, there is a charge for this service.
- If you're interested in establishing natural gas and/or electric service to a home or other building which does not already have service, you should contact your local Montana-Dakota office.

For Our Natural Gas Customers...

Natural gas is a colorless and odorless fuel. We maintain a constant, reliable supply to meet your heating, air conditioning, cooking, clothes drying and water heating needs. Our natural gas is produced from abundant domestic sources and is not vulnerable to supply disruptions by foreign governments.

Natural gas is also a very safe fuel. But, like other products in your home, it can be hazardous if misused. *We give natural gas a distinct odor for your safety. If you smell gas, call us immediately.* We will respond to all emergency requests at no charge.

On occasion, we enclose a scratch-and-sniff insert with your utility bill so you and your family can recognize the odor added to natural gas. If you would like to learn more about natural gas or have questions about its safe use, we would be glad to tell you more.

Keep all of your natural gas appliances and equipment clean and properly maintained to help ensure their safe operation. A trained Montana-Dakota service representative can assist you in this effort. Just call us to schedule a visit to your home. There is a charge for this service.

For Our Electric Customers...

We take pride in our record of reliable electric service. We never realize how much we depend on this silent servant until it is interrupted by a bad storm or equipment failure.

If your power should go out, find out if neighboring homes still have electric service. If they still have power, check your fuse box or circuit breaker panel. If a fuse is blown, or a circuit breaker is open, turn off the lights and appliances on that circuit. This will help prevent damage to your appliances and your electrical system as well. Then replace the fuse with the correct amperage for that circuit or turn on the breaker. If a fuse continues to blow or breaker to open, call an electrician to find and repair the problem.

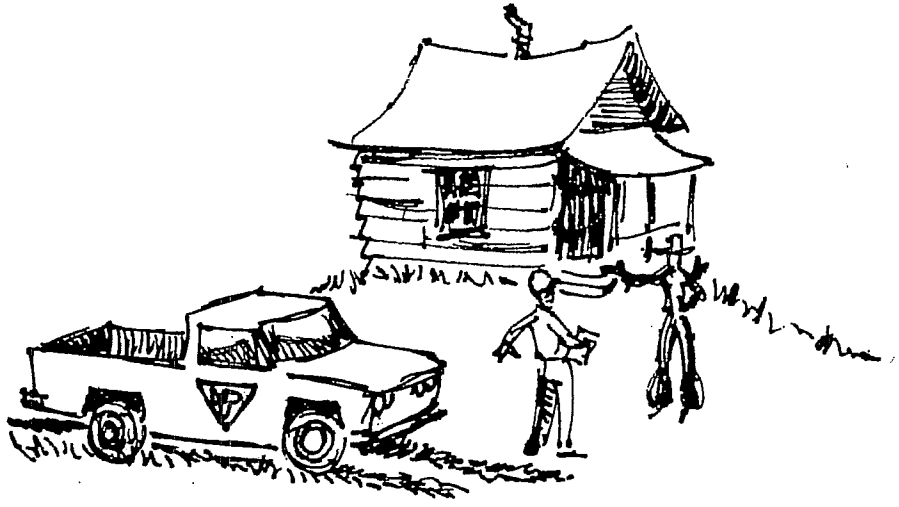
When the electric outage is not confined to your home, disconnect or turn off as many electrical appliances and lights as possible. This will help protect your equipment and reduce the initial demand for electricity when the power is reconnected. Leave one light switched to the "on" position so you can tell when power is restored. Then you can reconnect appliances one at a time.

Call Montana-Dakota to report any outage not confined to your home unless you know a neighbor has already reported it.

Montana-Dakota's primary goal is to furnish satisfactory electric service at fair rates. But, our electric system is widespread and exposed to storms and other factors we cannot control. Although we employ the latest developments in equipment and operating methods to maintain adequate service, we cannot guarantee uninterrupted power. If you have computers and other sensitive equipment that require high grade, uninterrupted power, you should check with your computer equipment supplier for information on devices that will ensure the power quality you need.

Saving Energy and Money...

Managing your utility bill begins at home with you. There are three ways to help hold household energy costs down.



- **Weatherize your home.** Projects can be as simple as caulking and weatherstripping around windows and doors to a major undertaking like adding wall insulation. Montana-Dakota can provide you with free booklets that contain everything from conservation tips to "how to's" on weatherization projects. Just contact your local Montana-Dakota office for this information.
- **Change your living habits.** You can also save energy dollars by doing things a little differently around your home. For example, reduce the temperature setting on your water heater to the "warm" position and dial your winter thermostat temperature back to 60° F. at night. Pull the drapes at night to minimize heat loss through windows. We can give you free information of these and other no-cost conservation tips at your request.
- **Use appliances and equipment that are more energy efficient.** Most appliance dealers and heating contractors sell products that are much more energy efficient than those available just a decade ago. Although you'll pay a higher price for these models, they'll more than make up the difference through energy savings. It makes good sense to insist on a high efficiency model when you make your next major appliance purchase.

What to Do if You Have Trouble Paying...

Montana-Dakota is concerned when customers have difficulty paying their utility bills. If you can't pay your bill on time, call us. We will be happy to sit down with you and talk about your situation and we'll try to find a solution to help you.

- **Payment Arrangements.** Payment arrangements can be made to help get your payments back on schedule. The amount of each payment is based on: the amount of the unpaid balance; the customer's ability to pay; the customer's payment record; and the length of time the bill has been outstanding.
- **Energy Assistance.** The federal government provides funding to each state to assist low-income households in paying their energy bills. In some areas, there are also private, charitable funds available for emergency assistance. Your local Montana-Dakota office can direct you to the agencies responsible for these programs.
- **Weatherization Programs.** Assistance is available through some government agencies to weatherize eligible low-income homes. Adding insulation, caulking and weatherstripping are examples of the weatherization measures available at no cost to the homeowner. The added measures not only reduce the home's heating needs, but also improve its comfort.
- **Third Party Notice.** Any Montana-Dakota customer can voluntarily select another person to be notified before utility service is disconnected. This "third party" is selected by the customer and usually is a friend, relative, clergyman or government agency. The third party program is strictly confidential.

  The purpose of the third party is to make sure the customer receives and understands the disconnection notice and to help take action to prevent disconnection. Your local Montana-Dakota office will start the program after receiving a request from you or another responsible person.

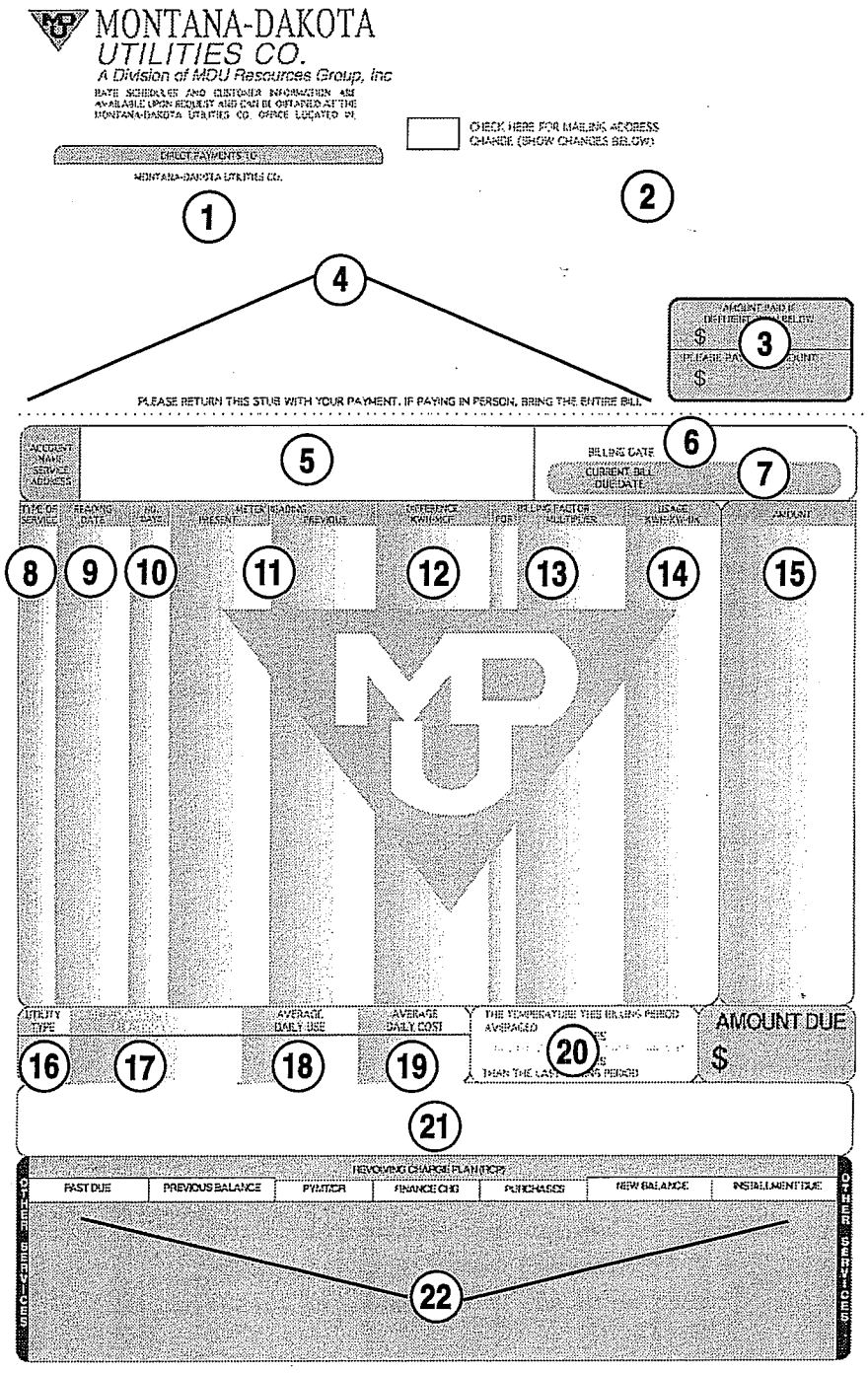
How You Buy Energy...

Every time you flip a switch or turn a dial you buy energy. It's our job to bring electricity and/or natural gas to your meters, but you are responsible for how it is used inside your home. You ***do*** have control over your bill. By being aware of how you use energy, and by eliminating waste, you may be able to reduce your bill, or at least keep it from increasing as quickly as it might otherwise.

- **Natural Gas:** Your natural gas meter measures the *volume* of gas you use each billing period. Your bill shows the difference between your meter's present and previous readings in units called "Mcf" (an Mcf is one thousand cubic feet). Since the energy content of an Mcf of natural gas varies throughout our service area, we convert the volume of gas you use to *energy* units called "decatherms" (a decatherm, or dk, equals one million British thermal units of energy). By doing this, we ensure you are billed for the amount of energy you used based on the energy content of natural gas for your locality. You pay neither more nor less than your fair share.
- **Electricity:** Your consumption of electricity is measured and billed in units called kilowatt-hours (kwh). The number of kilowatt-hours you use each month is shown on your bill. Light bulbs can be used to help you understand kilowatt-hours. If you turn on ten 100-watt bulbs, you create a demand of 1,000 watts of 1 kilowatt of electricity (10 bulbs x 100 watts). If those 10 bulbs burn for one hour, you've used one kilowatt-hour of electricity. If the lights burn for three hours, you have used 3 kwh. The expected demand in kilowatts is indicated on most electrical appliances.
- **Meters:** Your electric and natural gas meters measure how much energy you use. Meters are accurate instruments and care must be taken to ensure they are not damaged. Tampering with a utility meter is not only a criminal offense, but it's dangerous too.

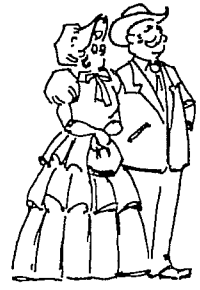
  Your meters are read about the same date every month. If we are unable to read your meter because of extreme weather conditions, or if the meter is inside and you're not home, we may have to estimate usage on your bill that month. Any difference between our estimate and your actual usage will be corrected automatically the next time your meter is read.

  After your meter is read, your bill is figured according to the rates that have been approved by the Public Service Commission or the Public Utilities Commission of your state. Copies of these rates are available at *your local Montana-Dakota office.* When there is a change in rates, we include an explanation of the change with your utility bill.



Many customers ask why their utility bill is different from their neighbor's. Again, there are several reasons:

Housing Differences. The type of construction, size and location of a house have a lot to do with how much energy it uses. A large, well-insulated house protected from the wind may use less heating energy than a small, poorly insulated house exposed to cold winter gusts.



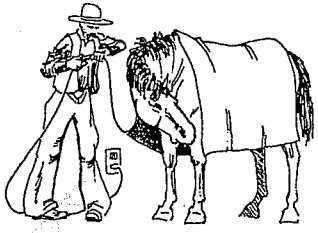
Differences in Occupancy. A dwelling's utility costs are also affected by its number of occupants, their ages and living habits. Since preferences in room temperatures, laundering, bathing and cooking styles differ among households, differences should be expected in the amount of energy used by dwellings even in the same neighborhood.

Appliances. The number of appliances found in a home and how often they are used can significantly affect energy usage, especially electricity.

Life-style. Stay-at-homes tend to use more energy than those who are out frequently.

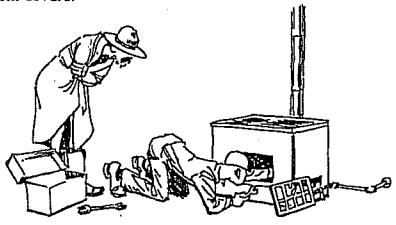
Vacations. Your home will probably use less energy when you're away. But, remember your refrigerator and maybe your furnace and other appliances continue to operate (and use energy) while you're gone.

Appliances. Adding appliances or appliances that need cleaning or repair usually use more energy.



Seasonal Uses. Car engine heaters to help start your car on a cold winter morning or the extra refrigerator you use to cool additional food and beverages are examples of items that could increase your bills during different times of the year.

Number of Billing Days. Your billing days may vary. The more days you've used energy, the higher your bill will be. Your utility bill tells you how many days your bill covers.



Other Services. You may have incurred a charge for some service or purchased an appliance from Montana-Dakota. These costs added to your regular charge for energy will increase your bill.

How to Read Your Utility Bill...

Upper Portion *(Return with payment)*

1. Address of the Montana-Dakota office processing payments.
2. Your name and mailing address.
3. **Pay This Amount:** The amount you owe Montana-Dakota for this billing period.
4. Tear horizontally along perforation. The entire stub (upper portion) is to be returned to Montana-Dakota with your payment for prompt crediting of your account.

The other numbers and letters that appear on the upper portion of your bill are for Montana-Dakota office purposes only. Please do not write on or make any marks on the upper portion of your bill.

5. **Account Name and Service Address:** This number and name identifies your account on our records. It is the address where natural gas and/or electricity were used. We can serve you faster if you have this information available when you inquire about your bill.
6. **Billing Date:** The date this bill was printed.
7. **Due Date:** The date your bill for this month is due. A late payment charge may be added to overdue bills.
8. **Type of Service:** A two-letter code indicates your type of service. An explanation of your code(s) can be found on the back of your bill.
9. **Reading Date:** The date your meter was read.
10. **Number of Days:** The number of days between your present and previous meter readings. It shows the number of days of service covered by this bill.
11. **Meter Readings:** These numbers are the dial readings which appear on the face of your meter.
12. **Difference:** The amount of natural gas or electricity consumed. It is derived by subtracting the previous meter reading from the present meter reading.
13. **Billing Factor** (natural gas only): You'll notice a "TF" is displayed in the "for" column and a factor in the "multiplier" column. "TF" stands for thermal factor. A thermal factor is a combination of the energy content of the gas and the average atmospheric pressure at your location. The volume of gas displayed in the "difference" column is multiplied by the thermal factor to provide the total decatherms (dk) used.
14. **Usage kwh-kw-dk:** Shows the amount of e natural gas (dk) you used during the billi *Residential accounts are not billed for ele*
15. **Amount:** Your total price for electricity, g
16. **Utility Type:** Natural gas and/or electric.
17. **Electric Cost of Fuel Adjustment and Pur Adjustment:** The adjustments are shown per decatherm of natural gas used. These changes in the cost of fuels and natural g Montana-Dakota. Montana-Dakota receive these charges.
18. **Your Average Daily Usage This Month:** T show your average daily usage of electric gas during the current period.
19. **Your Average Daily Cost This Month:** Th how much it cost you for electricity and/ average day during the current billing pe
20. **Temperature differences:** This column c temperature of the current billing period temperature last month as well as last ye
21. **Inquiries: For any inquiries about your use the address and/or telephone numb**
22. **Other Services:** This part of the bill show than gas or electric utility service, you m with the explanation given above. If you your bill, contact your local Montana-Dak happy to help you better understand our

This page folds out for an explanation of how to read your MDU bill.

How to Pay Your Bill...

- **By mail** – in the return envelope included with your bill. Don't forget to include the upper portion of your bill along with a check or money order. It is not a good idea to send cash through the mail. Please put the proper stamp on your envelope or the post office will return it to you.
- **In person** – at the Montana-Dakota office listed on your utility bill. Please bring your utility bill with you.
- **At payment drop boxes or local merchants** – which are authorized by Montana-Dakota to accept your payments. Call you local Montana-Dakota telephone number to find out if you can pay your bill in your community.
- **Direct bank payment** – Our "Easy Pay" plan allows you to have your bill automatically deducted from your bank account approximately 14 days after the bill is prepared. Call your local Montana-Dakota telephone number for details on "Easy Pay."

BALANCED BILLING

MDU

Balanced Billing...

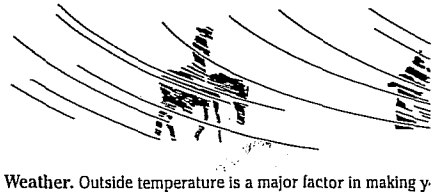
Balanced Billing is Montana-Dakota's voluntary plan to help you budget for your utility bills. Our severe weather causes utility bills to fluctuate widely during winter and other seasons.

Balanced Billing can reduce the impact of higher winter bills by averaging them with those during warmer months. It levels your bills throughout the year. There is no charge for this additional service.

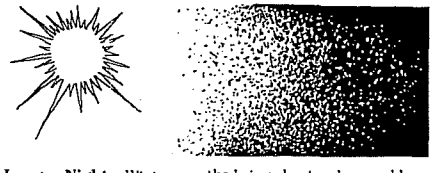
Your local office can give you more information on Balanced Billing.

Why Your Monthly Bills Vary...

There are many reasons why your utility bill may vary from r
Here are some examples of why bills vary:



Weather. Outside temperature is a major factor in making y
down. Cold, windy weather forces your furnace to provide m
your home comfortable. Likewise, hot, humid summers caus
conditioner to use more energy to cool your home.



Longer Nights. Winter months bring shorter days and long
mean you'll have more indoor activity and use more energy.

Change in Life-style. House guests, illness, new baby, and
more showers, more laundry and more cooking. Each increa
even if only for a short time.

Life-Sustaining Equipment...Please read carefully.

Anyone requiring life-sustaining equipment such as *iron lungs, chest respirators and rocking beds* must have an emergency standby power supply.

Life-sustaining equipment includes any electrically operated support system such as tank-type respirators (iron lungs), Cuirass-type respirators (chest respirators), intermittent positive pressure respirators, hemodialysis equipment (kidney machines), mechanical nebulizers, suction machines, rocking beds, apnea monitors or other similar equipment.

If you are a landlord with tenants using such equipment, please advise them of the safety equipment requirement to have an emergency standby power supply.

Montana-Dakota does everything possible to provide reliable service. But, because of weather, mechanical failure, and other circumstances beyond our control, we cannot guarantee uninterrupted electric service.

We Need Your Help...

- **Before you dig:**
  If you plan on digging deeper than one foot on your property, please call the applicable one-call centers to have your service line located:

One-Call Centers	
Montana	**1-800-424-5555**
North Dakota	**1-800-795-0555**
South Dakota	**1-800-781-7474**
Wyoming	**1-800-348-1030**

There is no charge during normal working hours. You should have the service line located *before* you begin any repairs to water or sewer lines, foundation for additions to your house, constructing a fence, planting trees, pouring a patio or driveway, or any other excavation which requires deep holes or trenches on your property.

We sincerely hope that you will always call for location of your service line before you start digging so that damage to the service line can be avoided. But, should you damage your service line, even if only the pipe coating is damaged, please call the Montana-Dakota office at the number shown on your bill or call 1-800-MDU-FAST and have someone inspect and repair the damage immediately. ***Never backfill or cover a damaged line until repairs have been made by Montana-Dakota.***

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Hello!

We're pleased to have you as one of our customers and we've prepared this booklet to tell you about our services.

We hope you find this information useful and that you will keep this booklet handy for future reference.

MDU employees are always available to help you with any questions or problems you might have about our services or about your MDU bills. Just contact us by telephone, stop in any of our offices or write us a letter. Our employees are trained to serve you and are willing to help.

- **After the storm:**
  - Storms can down power lines. **Storm-downed lines should always be considered dangerous – so stay at least six feet away.**
  - Power lines draped over highway barriers or fences can energize them for great distances. **Don't touch anything that's in contact with the wire.**
  - If a power line falls on your car, **stay in your car.** You're safe as long as you do.
  - Never try to cut fallen wires.
  - Consider every fallen wire dangerous. Report it to authorities or call Montana-Dakota.

- **To help insure uninterrupted gas service to your home:**
  - Try to keep gas meters and regulators free of heavy accumulations of ice or snow.
  - Do not strike meter when using snow blower, blades or shovels.

  Heavy snows, ice falling from eaves and various other problems can cause meters to snap off customer piping and interrupt service. Snow covering meters may cause the meter safety equipment to shut off service to your home.

  If your natural gas service is interrupted, for any reason, please call us. We appreciate your cooperation.

Special Services for You...

In addition to utility service and programs mentioned earlier in this booklet, Montana-Dakota offers special services. Ask your local Montana-Dakota office for further information.

- **Service Representatives** are available to help you with appliance inspections and repairs. There is a charge for this service.
- **Programs and speakers** on a variety of subjects are available at no charge to civic groups, senior clubs and other organizations.
- **Audio-Visual Library.** Montana-Dakota has a library with many films, slide programs, and videotapes that are available for customer use at no charge.
- **Gatekeeper Program.** Many Montana-Dakota employees are trained to recognize possible problems with elderly and disabled customers. Those employees alert local social service agencies when the well-being of those customers appears to be threatened.

We hope this booklet has given you a better understanding of the services Montana-Dakota provides. If you have any questions, or if you would like additional information, we are available to help you.

CUSTOMER INFORMATION BOOKLET

CUSTOMER INFORMATION BOOKLET

ADDITIONAL CUSTOMER INFORMATION FOR SOUTH DAKOTA CUSTOMERS

Montana-Dakota Utilities Co. 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 public utilities in the state.

MDU 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. In most cases, the problem will be solved with a visit or phone call to your nearest MDU office. Our employees are trained to help you.

MDU will make a full and prompt investigation of all written complaints received. Please address all written complaints to the manager at your nearest MDU office. The address of your local MDU office appears on your utility bill or it is listed in your local telephone directory.

DISPUTES

Whenever a customer advises MDU, before the disconnection of natural gas or electric service, that any part of the billing, charges or service is in dispute, MDU 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 MDU must notify the customer that the customer has the privilege 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
1-800-332-1782

CREDIT AND DEPOSIT POLICIES

MDU'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.

MDU will not require a deposit or guarantee from any new or present customers who have established good credit. MDU 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 any utility 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 MDU.

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 MDU's rules on file with the South Dakota Public Utilities Commission. These rules are available for your inspection for electric customers at the Mobridge MDU office and for natural gas customers at the Rapid City MDU office.
4. You have broken the terms of the contract for service with MDU or have failed to furnish those things necessary to obtain utility service.
5. You have failed to allow MDU 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 MDU's equipment or tampering with MDU'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 MDU 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 (20) 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. MDU 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 MDU 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 MDU's business offices are not open to the public.

The customer can pay a delinquent bill at the last minute to avoid disconnection. MDU'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, MDU 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. MDU 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. MDU shall not disconnect residential utility service from Nov. 1 to March 31 without adding an additional 30 days to the normal disconnection date. MDU 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, MDU 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

MDU 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 MDU in an attempt to force payment of that bill, except when that person, even though not personally liable to MDU, 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 MDU's customer rules. A complete listing of MDU customer rules and South Dakota Public Utilities Commission rules, regulations and rate schedules are available for your inspection at the Mobridge MDU office for electric customers and the Rapid City MDU office for natural gas customers. Your billing, payment and deposit records are also available to you for inspection. MDU will furnish additional information as you may reasonably request.

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

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

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

20292(11-80)
(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

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

Docket No.: NG02-011

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

(Rev. 11/80)

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

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

20511(9-76)
(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

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

X04-5216-2N
Rev. 9/98

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

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)

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)

[illegible]
[illegible]

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

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 _____ 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 _____, _____ 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-

INTERRUPTIBLE GENERAL GAS SERVICE AGREEMENT

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 _____ between Montana-Dakota Utilities Co. and _____ covering interruptible natural gas service to its facility located at _____. Deliveries and charges hereunder shall commence on _____ and expire on _____.

Delivery Point	Rate Schedule	Rate*	Maximum Interruptible Delivery Point Quantity Per Day (dk)	Maximum Interruptible Delivery Point Annual Quantity (dk)
_____	_____	_____	_____	_____

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 ____ day of _____, 20____.

By: _____
Representing _____

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

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

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 _____ between Montana-Dakota Utilities Co. and _____ covering natural gas service to its 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____.

By: _____
(Gas Supply Department)

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 [illegible] 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 [illegible] 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 $[illegible]. 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 [illegible]. 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

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)

21417(12-91)
(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

21467(12-01)
(Rev. 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 29527 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 / BID
____ 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 ($340) (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

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 (Form 30927 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.
DATE S.O. MAPPED & BY WHOM			DATE DIST. 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:
WELDER/FUSER:	LENGTH OF TEST:	TESTED BY:		PRESSURE TESTED TO: PSIG
INTERNAL COND. OF PIPE IF RETIRED: NA __WET __DRY __FAIR __POOR	EXTERNAL COND. OF PIPE IF BARE: __NA __GOOD __FAIR __POOR		TYPE OF COATING: NA __MW __STBU __OTHER	CONDITION OF COATING IF COATED: __NA __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.8380 _____ . _____ W Vintage _____
Retire _____ B _____ 30R.03PU.8376 _____ . _____ W Vintage _____

Other _____ B _____ 30__.03PU. _____ . _____ W
Other _____ B _____ 30__.03PU. _____ . _____ W

ITEM	SIZE	MAIN	STUB	SERV	ITEM	SIZE	MAIN	STUB	SERV
ANODE-MAG-					TEE-PL-BUTT-				
CAP-DR-					TEE-PL-BUTT-				
CAP-PL-BUTT-					TEE-PL-TAP-				
CAP-PL-BUTT-					TEE-PL-TAP-				
CAP-PL-SKT-					TEE-PL-SKT-				
CAP-PL-SKT-					TEE-PL-SKT-				
CAP-WLD-					TEE-PL-HVT-				
COATING-TC-20					TEE-ST-ELF-				
COUP-PL-					TEE-STPTRN-				
COUP-PL-					TEE-STP-				
COUP-PL-BUTT-					TEE-SVC-H17500-				
COUP-PL-BUTT-					TEE-TAS-MU-				
COUP-PL-ELF-					TEE-TS-MU-				
COUP-PL-ELF-					TEE-WLD-				
DI-BU-WI-SPL					TRNS-PK-				
ELL-PL-90-					VLV-SLW- -INS				
ELL-PL-90-SKT-									
ELL-PL-90-SKT-					ITEM	ITEM NO.	MAIN	STUB	SERV
ELL-PL-45-BUTT-					EXEMPT MATERIAL	3999999			
ELL-PL-45-BUTT-					EXEMPT MATERIAL	3999999			
ELL-PL-90-BUTT-					WI-LOC-GU614-HMWPE	2579007			
ELL-PL-90-BUTT-					SMALL FITTINGS	2999991			
ELL-WLD-45-									
ELL-WLD-90-									
ELL-WLD-90LR-									
EFV-PL-									
LSF-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					WASTE MATERIAL				
RIS-36V-									
SLV-PL-S									

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

Docket No.: NG02-011

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.
A Division of MDU Resources Group, Inc.

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, including any and all claims and liability arising out of any negligent acts of the Company.

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: _____

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	))))	**DECISION AND ORDER APPROVING SETTLEMENT STIPULATION NG02-011**

On December 30, 2002, 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 $2,173,380. On January 16, 2003, the Commission suspended the proposed schedule of rates for 90 days beyond January 30, 2003. On April 1, 2003, Commission Staff recommended that the suspension of the tariff be further extended for 60 days.

At its April 1, 2003, meeting, the Commission considered this matter. MDU concurred with Staff's recommendation. The Commission voted unanimously to grant the extension sought by Commission Staff. On April 30, 2003, the Commission received MDU's motion to continue and reschedule the hearing.

At its May 6, 2003, meeting, the Commission considered this matter. MDU agreed to suspend implementing the proposed rate increase for 30 days after the June 29, 2003, expiration date. The Commission voted unanimously to grant the continuance. On May 22, 2003, the Commission received MDU's motion to extend deadline for rebuttal testimony to June 6, 2003.

At its June 3, 2003, meeting, the Commission considered this matter. The Commission voted unanimously to grant MDU's motion to extend deadline for rebuttal testimony to June 6, 2003. On June 13, 2003, the Commission received a motion to continue and reschedule the hearing and further suspend rates from MDU and Commission Staff.

At its June 17, 2003, meeting, the Commission considered this matter. The Commission voted unanimously to grant MDU's and Commission Staff's motion to continue and reschedule the hearing and further suspend rates.

On October 27, 2003, the Commission received a joint motion for approval of settlement stipulation and staff memorandum supporting settlement stipulation from Staff.

Based on the Joint Motion for Approval of the Proposed Settlement Stipulation, the Commission noticed the Settlement Stipulation for consideration on December 2, 2003, at 1:30 P.M., in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota. On December 1, 2003, the Commission notified the parties that the meeting location had been changed to the Kneip Room, Governors Inn, 700 West Sioux Avenue, Pierre, South Dakota. The Commission also notified John Reints, complainant in Docket No. CN03-003, of the original meeting time and place and the change of location.

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 December 2, 2003, the Commission heard from MDU and Commission Staff concerning the proposed Settlement Stipulation. After examining the parties as to issues of concern to the

THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

RECEIVED

DEC 15 2003

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

= =

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE

NG02-011

= =

Transcript of Proceedings
December 2, 2003

= =

BEFORE THE PUBLIC UTILITIES COMMISSION,
ROBERT SAHR, CHAIRMAN
GARY HANSON, VICE CHAIRMAN
JIM BURG, COMMISSIONER

ORIGINAL

COMMISSION STAFF
John Smith
Karen Cremer
Harlan Best
Keith Senger
Dave Jacobson
Michele Farris
Heather Forney

APPEARANCES

David Gerdes
Donald R. Ball
Tamie A. Aberle
Rita A. Mulken

Reported By Cheri McComsey Wittler, RPR

PRECISION REPORTING
L I M I T E D

APPEARANCES BY TELEPHONE

Bob Towers

= =

TRANSCRIPT OF PROCEEDINGS, held in the above-entitled matter, at the Governor's Inn, 700 West Sioux Avenue, Pierre, South Dakota, on the 2nd day of December 2003, commencing at 1:30 p.m.

1 CHAIRMAN SAHR: Good afternoon.
2 This is the time and place for the South Dakota
3 Public Utilities Commission hearing for NG02-011.
4 It's Tuesday, December 2, 2003 at approximately
5 1:30 p.m.
6 I am Chairman Bob Sahr, and with me today are
7 Vice Chairman, Gary Hanson, and Commissioner
8 Jim Burg. And I'd like to take a role call of
9 anyone who's appearing telephonically.
10 Mr. Towers, are you on the line?
11 MR. TOWERS: Yes. Bob Towers. I'm
12 here.
13 CHAIRMAN SAHR: Who are you with?
14 MR. TOWERS: I'm with Chesapeake
15 Regulatory Consultants.
16 CHAIRMAN SAHR: Is there anyone else
17 on the phone line?
18 All right. If not, then we've got the role
19 taken care of, and should we just go with MDU
20 first? Staff or MDU?
21 MDU, why don't you go ahead and proceed.
22 MR. BALL: We can go first. Thank
23 you, Mr. Chairman. My name is Don Ball, and I'm
24 with Montana-Dakota Utilities Company.
25 Today we are considering the settlement

1 stipulation which was filed with you on October 27.
2 This results from the natural gas rate case for
3 our Black Hills system that we filed on
4 December 30, 2003.
5 In that application we filed for an increase
6 of approximately $2.2 million. And throughout the
7 course of the proceeding the staff investigated
8 that application. They filed testimony. We
9 subsequently entered into negotiating sessions, and
10 as a result of those sessions, we were successful
11 in coming to the settlement stipulation that you
12 see before you today.
13 This stipulation resolves all issues in this
14 proceeding. And, in summary, it calls for an
15 annual revenue increase of just over $1.3 million,
16 which is just about a 3.2 percent overall increase,
17 and a number of other issues that you see in the
18 settlement agreement.
19 With that, I'll -- we're here to answer any
20 questions you might have. With me, of course, is
21 Dave Gerdes, our attorney. To my right is
22 Tamie Aberle, our pricing and tariff manager, and
23 to her right is Rita Mulkern, our regulatory
24 analysis manager.
25 CHAIRMAN SAHR: Thank you. That's a

1 good reminder that I should take appearances.
2 Mr. Gerdes.
3 MR. GERDES: Mr. Chairman, members
4 of the Commission, I'm Dave Gerdes. I'm a lawyer
5 from Pierre, and I represent Montana-Dakota
6 Utilities Company in this proceeding.
7 And I think just procedurally and technically
8 for the record, the Commission has before it a
9 joint motion for approval of the settlement
10 stipulation which was filed with the stipulation.
11 And I think that's probably procedurally what we
12 need in order to approve -- or granting the motion,
13 I would say, or not granting the motion, if that's
14 your choice.
15 CHAIRMAN SAHR: Thank you. Staff.
16 COMMISSIONER BURG: You're
17 recommending which?
18 MR. GERDES: We'd recommend
19 approval.
20 MS. CREMER: This is Karen Cremer
21 with staff, and I would agree with Mr. Gerdes that
22 what's in front of you is the joint motion for
23 approval of the settlement stipulation, and as
24 noted, it is filed jointly and staff would also
25 recommend approval of the settlement stipulation.

1 Mr. Towers would be available for any
2 questions, as is Dave and Michelle and Keith.
3 CHAIRMAN SAHR: Mr. Towers, do you
4 have anything to add?
5 MR. TOWERS: No, I don't.
6 CHAIRMAN SAHR: Thank you.
7 Commissioners, questions, comments?
8 COMMISSIONER BURG: Just one I
9 probably have. Given the discussion this morning,
10 I think if I remember right in reading it that
11 there is an increase in the minimum charge in this
12 settlement; is that correct?
13 MR. BALL: That is correct. For a
14 residential customer our current monthly fixed
15 charge or base rate is $7. And under the
16 settlement stipulation that would go to 7.60 per
17 month for a residential customer.
18 I should note also that along with that
19 there's a policy change in the company. And that
20 policy change is that the company will -- for all
21 new and replacement service lines the company will
22 own that.
23 In the past the customers have owned their own
24 service line. And as a result they were
25 responsible for maintenance or replacement of those

1 service lines.
2 So this is a shift in that policy, and the
3 company will just simply take over ownership of
4 all --
5 COMMISSIONER BURG: Let me get that
6 straight. All service lines, not just new or added
7 ones; is that correct?
8 MR. BALL: Well, right now the
9 customers own their own service lines. To the
10 extent that those service lines remain viable
11 facilities, they will simply be owned by the
12 customer. But if they need replacement, we will
13 replace them at the company's expense.
14 COMMISSIONER BURG: How about any
15 kind of maintenance?
16 MS. MULKERN: Currently the company
17 is responsible for maintenance of the service
18 lines, and they will continue to do the maintenance
19 on all service lines.
20 COMMISSIONER BURG: Is there any
21 situation where those residences change hands --
22 will those lines continue to stay with those if
23 they're owned by the former residents, or is there
24 any kind of way of shifting the ownership?
25 MR. BALL: They'll simply stay with

1 whoever the customer is.
2 COMMISSIONER BURG: The last
3 question, is there any increased gas included in
4 that increased customer charge?
5 MR. BALL: No. There's no gas
6 included in that.
7 COMMISSIONER BURG: Yours don't have
8 any gas included?
9 MR. BALL: That's correct.
10 COMMISSIONER BURG: Historically has
11 there?
12 MR. BALL: At one time there was,
13 but at least since '94 there has been no gas
14 included with the monthly fixed charge.
15 COMMISSIONER BURG: Okay. I wasn't
16 aware of that.
17 CHAIRMAN SAHR: I guess I don't mean
18 to -- (Inaudible) -- MDU and staff. On this
19 ownership change, so to speak, what do you think
20 the typical customer's perspective would be on
21 that? Do you see this as a welcomed change?
22 Because perhaps there's some -- you don't have
23 the possibility of having the higher expenses if
24 something goes wrong, or what do you see as the
25 customer's perspective on this?

MR. RISLOV: If I can interrupt for a second, this is Greg Rislov. Could you explain, number one, exactly what the service is and, number two, what the average service would cost to replace if a customer had to replace it, kind of give it some perspective?

With regard to the system, what is the service? What does that have to do with the system?

MR. BALL: In a typical gas system -- and let's say that our main line runs down the alley. There's a main that would run down the alley or the street, whatever. There's what we call a service stove, which is a piece of pipe that connects to the main that runs to the property line.

And then from the property line up to the service riser where the pipe comes out of the ground right by the house that's what's called the service line.

So under this proposal we'll simply own everything through the downstream side of the meter. You know, the customer will continue to own their own house piping, which they have done forever.

COMMISSIONER BURG: Who owns the meter?

MR. BALL: We own the meter and the regulator.

COMMISSIONER BURG: Now and under the new policy?

MR. BALL: Yes. Now and under the new policy. The only change is the service line which is typically from the property line to the riser.

CHAIRMAN SAHR: So right now let's say I have a problem with my service line. Do I pay for that? Does MDU pay for that? How does that work?

MR. BALL: If you were in the Black Hills area and you owned the service line and there was a problem with it, say it leaked or something, we would probably replace it and bill you for that. And we're talking typically the range of a couple hundred dollars.

CHAIRMAN SAHR: Under this new system if it was a new line that was put in with this policy change, then MDU would pay for that?

MR. BALL: Yes. We will pay for the new line and even if you're a current customer and

there's a problem with your service line, we'll go and replace the service line and we will own it. You will not have to pay for replacement.

CHAIRMAN SAHR: For instance, on my house, if this happened as an existing line, then the company would actually come in and do the work and then you would -- you would pay for it as opposed to the customer?

MR. BALL: Yes. We would pay for it. I might note I assume you live in Pierre. We already own the service line. We started it that way.

CHAIRMAN SAHR: Sure.

MR. BALL: So this will essentially make our Black Hills system now consistent with the remainder of our gas service area.

CHAIRMAN SAHR: And I am actually not a customer here, but that's neither here nor there. I do have a line going to my house, though. We can talk about that later.

MR. BALL: We sell --

(Discussion off the record)

COMMISSIONER BURG: So your idea is if you go out far enough, you will end up replacing and owning them all?

1 MR. BALL: Yes. That's the idea.
2 MR. JACOBSON: It may be nice to
3 know too, Martin was involved in this decision, and
4 his input into it was it was very important for the
5 company to have this policy in place. Being out
6 there on a day-to-day basis with pipeline
7 inspection and stuff, he highly recommended this
8 new policy.
9 MR. BALL: Let me address your
10 specific question just a little more. I guess from
11 the company's perspective we welcome the change
12 because, quite frankly, if you look at telephone,
13 cable TV, even electric service, those utilities
14 own everything right up to the house.
15 So we're kind of the last holdout, if you
16 will. We're different than the rest of the world.
17 Our customers do not understand why they have to
18 pay for a service line because they don't pay the
19 cable company for the last 50 or 70 feet of wire or
20 they don't even pay the electric company to hook a
21 wire to their house. So this will put us there.
22 From a customer perspective we think it's also
23 a good thing, simply because of the
24 misunderstandings that have arisen. They're
25 saying, well, my service line works perfectly,

okay. But we are subject to DOT requirements on pipeline inspection and safety, and they just don't understand. So it will be a lot less hassle for us and we think a very good thing for our customers.

COMMISSIONER BURG: Two questions I have continuing on this. One is there's really no value to the customer, is there? I mean, nobody can claim that there's a value in that pipe that's in the ground to them, is there?

MR. BALL: I don't see that.

COMMISSIONER BURG: I don't see it either. So the question I have is did you consider or is there a reason you did not just decide to just own all of them, take them over, or did you feel that you had to wait until there was a replacement?

MR. BALL: Well, I think it's just more efficient to wait until there's a replacement. If we want to own all of them, you're going to run into a customer who says, well, I want some money for my service line.

What do you pay for 20 or 30-year old service line? Quite frankly, it's cheaper to put a new one in.

COMMISSIONER BURG: That's all I

1 have.

2 CHAIRMAN SAHR: Thank you. So staff

3 doesn't see any downside to making this change?

4 MR. JACOBSON: No.

5 MR. TOWERS: I certainly don't.

6 CHAIRMAN SAHR: Thank you.

7 VICE CHAIR HANSON: Mr. Chairman, I

8 would just note that water companies have similar

9 challenges and having been a utilities

10 Commissioner -- yes, utilities Commissioner some

11 years ago this was one of the biggest challenges

12 that we had when someone would have a problem with

13 their service line is understanding that it was

14 owned from a similar situation, from the shutoff to

15 the home, and why should all of a sudden -- it's

16 quite expensive to dig up a water line and replace

17 it.

18 And this, I think, is a very good step forward

19 in providing better services and eliminating those

20 challenges to the consumer.

21 CHAIRMAN SAHR: Thank you. Any

22 other questions or comments on this particular

23 charge?

24 VICE CHAIR HANSON: Move for

25 approval. Do you need one?

1 CHAIRMAN SAHR: Actually I do have
2 another couple of questions. If Jim seconds.
3 COMMISSIONER BURG: I hesitate at
4 indifference to the Chair.
5 VICE CHAIR HANSON: I didn't see his
6 list of questions.
7 CHAIRMAN SAHR: You know, I
8 definitely can see merit to this. I think it makes
9 a whole lot of sense. One of the things that I
10 would like to flush out is the DDSM charge, and
11 that's the distribution delivery stabilization
12 mechanism.
13 And I'd like you to talk a little bit about
14 how that's actually going to work, and I would
15 encourage advisers to ask any questions they have
16 along these lines.
17 But maybe you can just give us a little more
18 overview on how you see this working and how it may
19 work depending on the fluctuations year to year
20 based on warm years, cold years, so forth.
21 MR. BALL: Tamie Aberle will be
22 happy to do that for you.
23 MS. ABERLE: This is Tamie Aberle
24 with Montana-Dakota. The DDSM, or distribution
25 delivery stabilization mechanism, is a means of

levelizing customer bills during the winter periods.

The mechanism would be applied to bills starting with the bills we issue on November 1 in a typical year. And the mechanism would take a look at -- each customer's bill basically would be adjusted to reflect normal weather. And we do that by first eliminating the base use from that customer's usage during that particular billing cycle and then adjusting that to reflect the weather difference.

And we would do that based on what we call billing degree days, which is simply a calculation of the deviation from a base of 65 degrees. And this information is reported by the National Weather Service, and their reporting stations for the Black Hills area would be using the Rapid City Airport weather reporting station.

For just a simple example, if we looked at a customer that was billed 20 dekatherms during the month of January and the weather was 10 percent colder in that particular month, by applying this adjustment mechanism we would actually reduce that customer's bill by, in this case, 2.60.

1 Now if the reverse were to happen in that same
2 month and it was 120 percent warmer than normal, we
3 would increase the bill by 2.60.
4 The rates that we establish in the case are
5 based on normal weather. And this is the
6 distribution margin that I'm speaking of, and it is
7 not affected by the cost of gas. The gas commodity
8 would be whatever dekatherms are registered at that
9 home, that gas commodity would be billed on that
10 customer's bill.
11 This is just the distribution margin. And a
12 couple of reasons for that. There are fixed costs
13 that we know are not covered in that base rate, the
14 basic service charge, as we refer to it, even at
15 7.60, based on our analysis, that is not recovering
16 all of the fixed costs.
17 So to the extent there are fixed costs in that
18 energy component, in that distribution margin
19 component in colder weather customers are actually
20 contributing more toward fixed costs and in warmer
21 weather they're not contributing enough toward
22 fixed costs.
23 We see the adjustments as minimal on a
24 customer-by-customer basis, and yet it will provide
25 some stability in those bills during those winter

1 periods.

2 MR. JACOBSON: Just so I can clarify

3 what was handed out to you, Martin put this

4 together, and it's like Tamie just did. It's an

5 example of what the effects of the adjustment are

6 and kind of how it operates.

7 If you take a look at the top group of

8 numbers, small residential customer, which is

9 typically what most people are concerned about, the

10 usage for each month is what Martin has determined

11 is the average for customers in the Black Hills

12 region.

13 If you look at the next column, that is the

14 usage less the base use that Tamie has spoke about.

15 And this example is for each 1 percent warmer or

16 colder than normal. So, for instance, if it was

17 10 percent warmer or colder than normal, you can

18 basically multiply this by 10. This is how much it

19 will affect your bill each month.

20 And if you just follow it across -- I guess,

21 if you follow it down, you can see the effect, the

22 heating degree adjustment. You know, the revenue

23 adjustment for an entire 12-month period for each

24 degree above or -- for each percentage above or

25 below normal, it's 79 cents. There's different

1 ways to look at it. The heating degree day
2 adjustment is the dollar amount per percentage
3 above or below normal.
4 As Tamie stated, we have to remember that this
5 does not include the gas costs. And, for instance,
6 the first line there with 15 dekatherms of usage,
7 right now I don't know that gas cost is probably
8 around or above $5. So the effect of this
9 charge -- if weather was 10 percent warmer than
10 normal, 15 dekatherms of usage -- or affects the
11 bill by 13 cents per percentage above or below
12 normal.
13 COMMISSIONER BURG: In this case it
14 would be down.
15 MR. JACOBSON: It could be either
16 way. It works the same either. If it's colder
17 than normal, it would be lowered. If it's warmer
18 than normal, your bill would increase by this
19 amount. It gives you an effect. It's not a really
20 dramatic --
21 You know, speaking to Martin about how cold
22 above or below normal it really can get, a huge
23 swing from between percent above or below normal.
24 That would be a drastic departure from normal
25 temperature.

1 Considering that, if you look at -- just look
2 at the month of January. 20 percent would be 2.60
3 for 15 dekatherms of usage, you know. If you have
4 any questions about that, I can answer it. If you
5 really want to get into the real details, we can
6 get Martin on the phone. He's at Northwestern
7 Public Service doing inspections right now. But
8 this was his exhibit explaining the effect.
9 CHAIRMAN SAHR: While we kind of
10 look over the exhibit I do have a question about
11 how this is going to appear on the customer's bill
12 and how it will be explained.
13 What is the anticipated method of billing this
14 and explaining it to the customer? I mean, is it
15 going to appear as a new charge, or what's it going
16 to look like?
17 MS. ABERLE: Yes. We have suggested
18 that it show as a separate line on the customer's
19 bill so they're aware of it, and at the time that
20 we implement the mechanism we would do a notice,
21 customer insert outside of the notice that would go
22 along with the rate case. So there would be a
23 specific insert relating just to the DDSM.
24 MR. SMITH: Does this vary by usage,
25 though? Is this a usage-based adjustment?

1 MS. ABERLE: Yes, it is.
2 MR. SMITH: So we won't be back to
3 another fixed cost?
4 MS. ABERLE: No. It's not fixed.
5 COMMISSIONER BURG: Is the purpose
6 of this to allow you to be sure you recover all of
7 those costs?
8 MS. ABERLE: It does both. It
9 does -- we have fixed costs that we have identified
10 when it occurs between abnormal -- in abnormal
11 weather which, you know, the normal weather is
12 based on a 30-year average. So in between those
13 times that we are recovering fixed costs and to the
14 extent it's colder than normal, customers aren't --
15 COMMISSIONER BURG: It doesn't
16 levelize as well.
17 MS. ABERLE: Yes.
18 CHAIRMAN SAHR: I'll play devil's
19 advocate here. With fixed costs would they be
20 better handled through a charge that is directly a
21 fixed charge cost like the 7.60 charge, or which
22 would be better in trying to recover fixed costs?
23 MS. ABERLE: Well, customers'
24 perception of a fixed cost have been troublesome
25 over the years, as we have seen this morning.

1 Probably not to that degree. But I think people
2 have a hard time associating the fixed charge with
3 more than just the meter hanging on their house at
4 times, when, in fact, it covers a lot more costs
5 that we have that are fixed in nature than that.
6 But that's certainly another way to eliminate
7 this is to truly reflect fixed costs, which in many
8 cases would be higher.
9 CHAIRMAN SAHR: Do other companies
10 have similar charges either in South Dakota or
11 elsewhere in the United States?
12 MS. ABERLE: There are about 35
13 companies today throughout the United States. I do
14 not believe there are any here in South Dakota that
15 have a mechanism similar to this in place.
16 CHAIRMAN SAHR: Do you have any
17 analysis or any -- anything that would indicate
18 whether customers like this sort of charge or --
19 not like a charge, but whether this is something
20 that the public's going to generally understand and
21 accept or if it's something that's going to cause
22 the phones to start ringing off the hook for
23 everyone saying what's this new charge on our bill
24 and why is it being done this way?
25 Have you done any sort of research on that?

MS. ABERLE: I do not have any sort of specific data on that.

CHAIRMAN SAHR: Do you know for a typical average customer -- and maybe this goes a little bit to this graph -- what sort of pluses and minuses are we going to see on their bill? I mean, 10 percent warmer or colder, 20 percent warmer or colder?

What sort of fluctuation are we going to be seeing? Do you have any idea or any analysis on what it's going to look like?

MS. ABERLE: Well, I think this table does a good job of exhibiting.

CHAIRMAN SAHR: What are they translating --

MS. ABERLE: Well, if you look at January on this table -- I guess it's not my exhibit, but I am talking about it.

MR. JACOBSON: It may be more my responsibility to speak to it. For instance, if you look at January, an average residential small metered customer uses 15 dekatherms of usage. The weather temperature sensitive portion of that usage is 13.09 dekatherms. So that is what the adjustment is going to affect.

If it's 1 percent warmer or colder than normal, then the factor you multiply that 13.09 dekatherms by is 1.01 or 1 percent. And you end up with the heating -- when Martin put this together, I mean, heating degree adjustment, I was assuming that meant revenues, but I'm not --

MS. ABERLE: If I could. This is Tamie Aberle again. I believe that would be the dekatherm adjustment, if you will.

MR. JACOBSON: Right.

MS. ABERLE: And that would be applied to the distribution margin or the energy charge, which in the case would be 1.435, $1.435. So in that particular month the adjustment applied to that bill would be .13 times 1.435. And then in the last column is if it was 1 percent warmer in every one of the winter months, that particular customer would see a total of adjustment of 79 cents.

CHAIRMAN SAHR: For the month, for the year?

MS. ABERLE: This would be for the whole season. If it's 1 percent warmer, if we just assume this is warmer, it would be 79 cents. So if it were 10 percent warmer, it would be 7.90 over

1 that entire winter period.
2 CHAIRMAN SAHR: So we're talking
3 about a fairly small deviation.
4 MS. ABERLE: Yes.
5 COMMISSIONER BURG: Conversely, if
6 it's colder you'd have --
7 MS. ABERLE: Yes.
8 CHAIRMAN SAHR: I think you answered
9 part of my next question because I was asking for
10 the residential perspective. And I also want to
11 make sure, you know, if you had a larger business
12 that was under this sort of billing system, that
13 there wasn't going to be some sort of unfairness in
14 that you could be in business one year, out of
15 business the next year sort of thing.
16 And it sounds like even -- it appears from the
17 graph even for the larger businesses the
18 fluctuation's going to be relatively small, we're
19 not talking huge dollar amounts. Is that correct?
20 MS. ABERLE: That's correct.
21 COMMISSIONER BURG: I'd like to ask
22 a -- it's not even -- it's a related question, but
23 it's not directly to this at all. I know that you
24 make an adjustment or you adjusted for the sea
25 level, height above sea level because of gas

1 pressure; right?

2 Isn't that a factor at how you arrive at -- I

3 know, of course, the Black Hills has quite a

4 variation. Is there any adjustment within your

5 territory? Is there just one sea level adjustment?

6 MR. BALL: We bill on a dekatherm

7 basis, and a dekatherm, of course, is 1 million

8 BGs. So but to calculate the meter will actually

9 read in thousands of cubic feet or actually

10 hundreds of cubic feet.

11 And we do monitor the BTU content of gas on

12 our system at a number of points. And that's one

13 of the factors in converting the volumetric reading

14 to a dekatherm reading.

15 The other factor is altitude or the variation

16 from sea level. And those two factors are combined

17 into what we call the thermal factor.

18 COMMISSIONER BURG: But I guess my

19 question was given that the Black Hills has quite a

20 variation, do you have a different thermal factor

21 for higher areas in the hills, or is that pretty

22 well averaged in the hills?

23 MR. BALL: It's my community. So

24 Deadwood-Lead, for example, would have a different

25 one than Rapid City because they're a different

altitude.

COMMISSIONER BURG: That answers it.

CHAIRMAN SAHR: To kind of follow up on my last series of questions, do you see a relatively small impact of people who migrate off the system? If they happen to go off in a particular year where I guess the charges would be high as opposed to next year, or are there any sort of problems with people under this scheme --

MS. CREMER: If I can interrupt, it's a month to month. It will be on your bill every month. It shows up -- I was looking for -- do you have a sample bill? I didn't see -- it shows up like your PGA costs or whatever. I mean, it's going to be a line item on there.

MS. ABERLE: Yes. We're proposing actually to show bill detail on customer's bills, and it would be what -- this would be referred to as a real time mechanism. So it wouldn't be that we'd be accumulating these costs and charging later.

So there shouldn't be any issue associated with moving off the system. If it's colder in that particular month, they will receive the credit that month.

CHAIRMAN SAHR: So you're not at any point in time going to be overcollecting under any scenario?

MS. ABERLE: No.

CHAIRMAN SAHR: So colder months you're not going to be overcollecting, warmer --

MS. ABERLE: Colder we'd actually be refunding, and warmer we'd be collecting.

MR. JACOBSON: Over time there's colder than normal, warmer than normal will even out.

COMMISSIONER BURG: Especially when using a 30-year average.

MR. RISLOV: This is Greg Rislov again. Does the DDSM carry over as to something that just is what it is and over a 30-year period we expect it to average out?

In other words, is there a carrying amount on a DDSM?

MS. ABERLE: No, there is not.

MR. RISLOV: So it just is what it is and we expect the law of averages to take effect and over time everything will be made equal; correct?

MS. ABERLE: Yes.

1 MR. RISLOV: I don't know what other
2 questions Commissioner Sahr may have. I just
3 wanted to as long as we were on the DDSM --
4 CHAIRMAN SAHR: Mr. Towers, do you
5 have any comments?
6 MR. TOWERS: Yes. I have one
7 comment. Someone asked the question awhile ago
8 whether the costs that are recovered can be -- the
9 charge could just as well be covered in the
10 customer basic service charge.
11 And I think there would certainly be an
12 adverse customer effect. I think there could be
13 because while the -- (Inaudible).
14 MS. CREMER: Bob, you need to sit
15 right up to your phone or your mike. You're
16 cutting out, and the court reporter is having a
17 hard time hearing you.
18 MR. TOWERS: The question was asked
19 whether or not the charges that are covered in the
20 distribution charge, which is the volumetric
21 charge, could just as well be recovered in the
22 customer service charge -- (Inaudible) -- the
23 $7.50.
24 And I think my view is that there would be an
25 adverse customer reaction to that and justifiably

so. Because what that would do is to make each customer in a class pay the same amount for what we're calling fixed costs, without regard to his level of usage versus his neighbor's level.

The present arrangement have a vacant service charge and demand distribution charge breaks the bill. The first contribution covers the costs that can't be avoided, costs of -- (Inaudible).

(Discussion off the record)

MR. TOWERS: We're talking here about fixed costs, costs that are fixed from the company's point of view. They're the same basically from month to month. But the costs fall into two different categories from my perspective.

The first category is properly recoverable in the basic service charge. That includes -- those costs include the cost of having a meter, the cost of having a service line, the cost of preparing a bill.

Then there is another set of costs that are also fixed that are related to the construction, maintenance, and operation of distribution -- (Inaudible). Those costs not specifically because the customer of those -- (Inaudible) -- the aggregate all customers want that service.

1 That's why it's appropriate from my --
2 (Inaudible) -- to recover those costs through
3 basically a volumetric charge so the customers
4 contribute towards those costs based upon their --
5 (Inaudible). I don't know if I made that clear
6 or --
7 CHAIRMAN SAHR: Thank you. Do we
8 have any other questions or comments?
9 MR. RISLOV: I have a couple of
10 questions. And I appreciate what Mr. Towers just
11 said. Essentially the customer costs we're talking
12 about the avoidable, unavoidable costs related to
13 each individual customer, and I know there was some
14 discussion about fixed costs with regard to the
15 DDSM.
16 But, frankly, we were talking about nongas
17 costs, and we were intermixing categories in
18 dealing with those issues. At least that's what I
19 believe.
20 In the settlement I noticed that there were a
21 couple of questions that I had. Number one there
22 was a relatively significant adjustment to the
23 depreciation we serve. And that's a big curious
24 because it doesn't seem to be tied to any plant
25 changes that were also reflected in the settlement.

1 I was just curious about exactly what that
2 constitutes, what's behind that appreciation
3 adjustment.
4 MR. TOWERS: I can respond, Greg.
5 That came about during the negotiations to reach --
6 (Inaudible). And I believe it was --
7 (Inaudible) -- '94.
8 VICE CHAIR HANSON: Sir, this is
9 Commissioner Hanson. It may be the fact that I'm
10 new to this business, but I think there's a
11 challenge with your microphone, either in the
12 breathing or something of that nature. If you'd
13 slow it down a little bit. We're having a very
14 difficult time understanding what you're saying.
15 MR. TOWERS: Yes. I apologize. I
16 was saying I'm using a conventional phone.
17 There were issues raised in the 1994 case
18 concerning the depreciation rates that were being
19 used, the main and services account. That case was
20 resolved by settlement.
21 The same depreciation rate, and I'm talking
22 about the accrual rate, issues were raised in my
23 testimony in this case. And I recommended and
24 Senger made an adjustment to reflect so the change
25 in rates that the company explained in this case

1 and said the rates that I recommended were the same
2 rates that were -- that I had recommended in 1994.
3 (Discussion off the record)
4 The 1994 case was settled, and it was what you
5 might call a black fox settlement, with each party
6 having his own view of what the end result
7 reflected.
8 During the negotiations -- (Inaudible) -- I
9 did as much as I could from here and --
10 (Inaudible) -- discussed the fact that the staff
11 level determined what depreciation rates were
12 reflected in the 1994 settlement.
13 And we reached the conclusion during the
14 negotiations in this case that the staff had not
15 relinquished its position in 1994 and that the
16 rates that it was then recommending were actually
17 implemented and reflected in the gas services rates
18 that were established in that case.
19 Now the problem arose because the company did
20 not want to "adopt" those supreme -- (Inaudible)
21 the rate that it had requested in 1994. In
22 fairness in this case the staff thought it
23 believed -- it had prevailed on that issue in 1994,
24 that it was appropriate to make an adjustment to
25 the depreciation reserve in this case that would

1 reflect what type that service would be as the
2 staff depreciation rate -- (Inaudible) -- 1994.
3 CHAIRMAN SAHR: I don't know why the
4 4s keep disappearing. I won't ask you to speak in
5 a shrill, but I think for some reason it's killing
6 off and I don't know if it's pitch or what it may
7 be, but when you hit those dates maybe just slow
8 down a little bit.
9 MR. TOWERS: Okay. We reconstructed
10 in this case the depreciation reserve to reflect
11 what that depreciation reserve would be had the
12 company adopted the depreciation -- (Inaudible) --
13 that staff now believes were reflected in that
14 settlement of the 1994 case.
15 That's why the adjustment that Mr. Rislov
16 identified appears to be so large in relation to
17 changes in the approval rate, which were real
18 subject under discussion in our testimony.
19 MR. RISLOV: Thank you. I
20 understand. With regard to labor -- and it
21 appeared to me going through the settlement
22 material and the factual documentation I had with
23 regard to numbers that it was a fairly routine
24 adjustment.
25 On the other hand, the labor and labor-related

1 adjustments that appeared in the settlement over
2 and above staff's initial filing were, from my
3 point of view, fairly large, fairly significant
4 changes to cost of services.
5 And I think it's worthwhile to get a bit of
6 explanation why the labor and labor-related cost
7 expanded so much between staff's initial filing and
8 the subsequent settlement agreement between staff
9 and MDU.
10 I don't know who chooses to address it. I'm
11 not picky.
12 MR. JACOBSON: Well, I can address
13 it from staff's standpoint. We simply asked for
14 updates as it became known and measurable. As, you
15 know, labor is divided into union and nonunion
16 increases, we were at the -- the second portion of
17 the union increase was the result of a new contract
18 that was signed.
19 And I would agree that the increase in the
20 first year of the new contract was significantly
21 above what had been in the prior contract.
22 However, in my analysis of that, the prior
23 contract which had been in effect for five years
24 had -- considering economic conditions at the time,
25 among other things, had what I would consider low

1 salary increases. And if nothing else, just
2 comparing it to wages offered to State Government
3 employees I was -- it seemed like the five
4 consecutive years before the new contract the rate
5 increases were very low and that possibly the large
6 increase reflected in the first year of the new
7 contract was kind of a catch-up, which occasionally
8 happens even within State Government.
9 And because we knew it was actually in effect,
10 staff did accept it at the time. But it was
11 something over 7 percent for the first year. If
12 the company would want to explain more about that.
13 MR. BALL: I'll take a little shot
14 at that. In the union labor agreement we knew
15 going in by comparing to other utilities, for
16 example, what we're paying our operating people
17 versus what other companies are paying and as
18 Mr. Jacobson indicated, the old contract was five
19 years old.
20 Quite frankly, our employees were pretty much
21 behind some other employees in other companies, and
22 it is kind of a catchup to kind of bring them up to
23 a parity.
24 I would note it's going to take approximately
25 three years under the new agreement to get them up

1 to the levels that some other companies are
2 currently paying some of their employees.
3 CHAIRMAN SAHR: What other companies
4 do you compare to?
5 MR. BALL: We look at Ottertail. We
6 look at Northwest, both in South Dakota and
7 Montana, probably Black Hills. And I'm sure there
8 are a couple of others, but I'm not aware of who
9 they are.
10 MR. RISLOV: We have a general idea,
11 I think, perhaps through the DDSM discussion of
12 what's happened with the rate design as it relates
13 to a smaller customer, smaller usage customers.
14 Are there any remarkable changes that will
15 affect the larger use customers on the system?
16 MS. ABERLE: No. There are -- I
17 believe it was provided in the settlement, but in
18 the other classes the base rates with the exception
19 of the small IT sales remain the same. The small
20 interruptible sales base rate was increased from
21 $40 per month to $50 per month, and along with that
22 there would have been a decrease in their energy
23 charge because there was no increase or decrease
24 allocated to that class.
25 So to the extent that the base rate increased,

1 the charge per dekatherm decreased on the small
2 interruptible transportation. There is also an
3 increase in that base rate charge.
4 MR. RISLOV: Thank you.
5 CHAIRMAN SAHR: I have a question
6 for Mr. Jacobson. And this morning we had a
7 consumer express some concerns about fixed charges.
8 And briefly I just wanted that addressed on the
9 record and get staff's perspective on fixed charges
10 and whether they are, you know, a "good" or "bad"
11 thing or a mixed bag, and I'd appreciate you
12 commenting on that briefly.
13 MR. JACOBSON: Since I've work here
14 the customer charges have always been an issue in
15 every case. Almost every case I'm ever aware of
16 the company came in with a much higher proposed
17 customer charge than ultimately staff or the
18 Commission's accepted.
19 But in our analysis of -- for instance, in our
20 analysis of fixed charges in this case Bob Towers
21 came in with a customer charge that was lower than
22 what we ultimately accepted, and we explained that
23 as part of the service line issue in this case.
24 Typically staff has always recognized that
25 fixed costs are appropriately recovered through a

1 fixed charge of that nature. We have never -- or
2 there have been several times in the past where we
3 have not moved to directly cover all fixed charges
4 because of a customer reaction.
5 Of course, the one case that was referred to
6 earlier was the Minnegasco case. And in that case
7 I believe we actually did a customer survey on the
8 issue and surveyed customers on if they felt that
9 level of increase was appropriate, and many did
10 not.
11 But it's been our case, although we never move
12 directly to recover -- or at least in most cases
13 have never moved to directly recover all of the
14 fixed charges through the customer charge, the
15 Commission has historically always moved in that
16 direction, understanding that some day they may get
17 to that level.
18 But I think there have been cases when we have
19 got to the level where we were actually recovering
20 what was agreed to as the fixed charge. In that
21 case there's certainly no reason to go any higher.
22 But, you know, this Commission staff and
23 historically the Commission have always agreed that
24 those customer charges are appropriate. And, in
25 fact, not charging the appropriate customer charge

1 or not at least moving in that direction results in
2 a subsidy flowing in the wrong direction, and a
3 less equitable result than otherwise acknowledging
4 those fixed charges is to try and recover it to
5 customer charges.
6 CHAIRMAN SAHR: Thank you. Any
7 other questions or comments?
8 MR. TOWERS: I'll try one more time.
9 The customer that we're talking about that Dave was
10 referring to -- (Inaudible) -- in the exhibit --
11 (Inaudible) -- is identified as -- (Inaudible).
12 (Discussion off the record)
13 VICE CHAIR HANSON: We didn't get
14 any of that, sir. We are just getting like one
15 syllable out of every word.
16 MR. TOWERS: I'm getting a lot of
17 feedback.
18 CHAIRMAN SAHR: I feel like staff
19 has sufficiently answered the question, Mr. Towers.
20 So I think due to the technical difficulties, I'm
21 comfortable that the flat charge was adequately
22 considered by staff and the type of concerns that
23 we've heard this morning were addressed in
24 considering what the proper rate structure is in
25 this particular case.

1 MR. TOWERS: Yes, they were.
2 CHAIRMAN SAHR: Thank you. Do you
3 want to restate your motion, or do you want to use
4 the old one?
5 VICE CHAIR HANSON: I haven't
6 withdrawn it yet, Mr. Chairman.
7 COMMISSIONER BURG: I'll second it.
8 CHAIRMAN SAHR: And I concur.
9 (Discussion off the record)
10 VICE CHAIR HANSON: Mr. Chairman, to
11 clarify my motion, I don't have an agenda in front
12 of me. I thought we were taking items
13 individually. So I was approving that particular
14 one.
15 However, I do believe that my motion was
16 germane to the entire item.
17 CHAIRMAN SAHR: Thank you.
18 MR. RISLOV: I have one question I
19 want to ask, and it doesn't relate to the issues
20 we've discussed, but do the tariffs read for
21 service on and after or for billings on and after?
22 MS. ABERLE: Service.
23 MR. BALL: Actually the stipulation
24 agreement indicated service rendered on and after
25 November 1, which has, of course, far past.

MR. RISLOV: So we're going to change that to February 1.

MR. BALL: I think we're going to have to change that to service rendered on and after December 2 would work for us.

MS. CREMER: I think that's what it has to be.

CHAIRMAN SAHR: Do we need a motion then?

MR. GERDES: I'd prefer one.

CHAIRMAN SAHR: I think we probably should have one since we approved the stipulation that now we're all acknowledging it's out of date. So is December 2 an appropriate date?

MS. CREMER: That's today. Right.

CHAIRMAN SAHR: Thank you.

COMMISSIONER BURG: I'll second that motion.

CHAIRMAN SAHR: I'll realize it's today.

VICE CHAIR HANSON: I'll concur.

CHAIRMAN SAHR: And I second.

COMMISSIONER BURG: You motioned. I seconded.

CHAIRMAN SAHR: I don't think I made

a motion. Seriously, let's clarify that, though. I do move that we make the effective date as of December 2.

COMMISSIONER BURG: Second.

VICE CHAIR HANSON: Concur.

CHAIRMAN SAHR: The case is resolved so we stand adjourned.

(The hearing concluded at 2:40 p.m.)

STATE OF SOUTH DAKOTA)

:SS CERTIFICATE

COUNTY OF HUGHES)

I, CHERI MCCOMSEY WITTLER, a Registered Professional Reporter and Notary Public in and for the State of South Dakota:

DO HEREBY CERTIFY that as the duly-appointed shorthand reporter, I took in shorthand the proceedings had in the above-entitled matter on the 2nd day of December 2003, and that the attached is a true and correct transcription of the proceedings so taken.

Dated at Pierre, South Dakota this 15th day of December 2003.

Cheri McComsey Wittler,
Notary Public and
Registered Professional Reporter

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Commission and having received satisfactory answers, the Commission voted to approve the Settlement Stipulation, including the attached customer notice and tariff sheets reflecting the new rates, with the exception of the effective date, which the Commission set, with the agreement of the parties, as December 2, 2003. Customer bills shall be prorated so that usage prior to December 2, 2003, is billed at the previous rates and usage on and after December 2, 2003, is billed at the rates approved in the Settlement Stipulation. MDU shall submit revised tariff sheets and a revised customer notice incorporating the approved effective date of December 2, 2003.

The tariff sheets approved and cancelled by this Order are as follows:

Section 1
Volume 2, Original Sheet No. 1 cancelling Volume 1, 15th Revised Sheet No. 1
Volume 2, Original Sheet No. 1.1 cancelling Volume 1, 6th Revised Sheet No. 1.1

Section 2
Volume 2, Original Sheet No. 1 cancelling Volume 1, 5th Revised Sheet No. 1
Volume 2, Original Sheet No. 1.1 cancelling Volume 1, 5th Revised Sheet No. 1.1

Section 3
Volume 2, Original Sheet No. 1
Volume 2, Original Sheet No. 2 cancelling Volume 1, 19th Revised Sheet No. 1
Volume 2, Original Sheet No. 5 cancelling Volume 1, 2nd Revised Sheet No. 5
Volume 2, Original Sheet No. 5.1 cancelling Volume 1, 2nd Revised Sheet No. 5.1
Volume 2, Original Sheet No. 7 cancelling Volume 1, 1st Revised Sheet No. 7
Volume 2, Original Sheet No. 11 cancelling Volume 1, 2nd Revised Sheet No. 11
Volume 2, Original Sheet No. 11.1
Volume 2, Original Sheet No. 12 cancelling Volume 1, 1st Revised Sheet No. 12
Volume 2, Original Sheet No. 12.1 cancelling Volume 1, 1st Revised Sheet No. 12.1
Volume 2, Original Sheet No. 12.2
Volume 2, Original Sheet No. 13 cancelling Volume 1, 2nd Revised Sheet No. 13
Volume 2, Original Sheet No. 13.1
Volume 2, Original Sheet No. 22 cancelling Volume 1, 1st Revised Sheet No. 22
Volume 2, Original Sheet No. 22.1 cancelling Volume 1, 1st Revised Sheet No. 22.1
Volume 2, Original Sheet No. 22.2 cancelling Volume 1, 2nd Revised Sheet No. 22.2
Volume 2, Original Sheet No. 22.3 cancelling Volume 1, 1st Revised Sheet No. 22.3
Volume 2, Original Sheet No. 22.4 cancelling Volume 1, 1st Revised Sheet No. 22.4
Volume 2, Original Sheet No. 22.5 cancelling Volume 1, 1st Revised Sheet No. 22.5
Volume 2, Original Sheet No. 22.6 cancelling Volume 1, 1st Revised Sheet No. 22.6
Volume 2, Original Sheet No. 22.7 cancelling Volume 1, 1st Revised Sheet No. 22.7
Volume 2, Original Sheet No. 22.8 cancelling Volume 1, 2nd Revised Sheet No. 22.8
Volume 1, 1st Revised Sheet No. 22.9 is cancelled
Volume 2, Original Sheet No. 26 cancelling Volume 1, 1st Revised Sheet No. 26
Volume 2, Original Sheet No. 26.1 cancelling Volume 1, 1st Revised Sheet No. 26.1
Volume 2, Original Sheet No. 26.2
Volume 2, Original Sheet No. 28
Volume 2, Original Sheet No. 28.1
Volume 2, Original Sheet No. 29 cancelling Volume 1, 3rd Revised Sheet No. 29
Volume 2, Original Sheet No. 29.1 cancelling Volume 1, 1st Revised Sheet No. 29.1
Volume 2, Original Sheet No. 29.2 cancelling Volume 1, 1st Revised Sheet No. 29.2
Volume 2, Original Sheet No. 29.3 cancelling Volume 1, 2nd Revised Sheet No. 29.3
Volume 2, Original Sheet No. 29.4 cancelling Volume 1, 2nd Revised Sheet No. 29.4
Volume 2, Original Sheet No. 29.5 cancelling Volume 1, 1st Revised Sheet No. 29.5

Volume 2, Original Sheet No. 30 cancelling Volume 1, 4th Revised Sheet No. 30
Volume 2, Original Sheet No. 30.1 cancelling Volume 1, 3rd Revised Sheet No. 30.1
Volume 2, Original Sheet No. 30.2 cancelling Volume 1, 3rd Revised Sheet No. 30.2
Volume 2, Original Sheet No. 30.3 cancelling Volume 1, 3rd Revised Sheet No. 30.3
Volume 2, Original Sheet No. 30.4 cancelling Volume 1, 2nd Revised Sheet No. 30.4
Volume 2, Original Sheet No. 30.5 cancelling Volume 1, Original Sheet No. 30.5

Section 4
Volume 2, Original Sheet No. 1 cancelling Volume 1, 9th Revised Sheet No. 1

Section 5
Volume 2, Original Sheet No. 1 cancelling Volume 1, 1st Revised Sheet No. 1
Volume 2, Original Sheet No. 1.1 cancelling Volume 1, 1st Revised Sheet No. 1.1
Volume 2, Original Sheet No. 1.2 cancelling Volume 1, 1st Revised Sheet No. 1.2
Volume 2, Original Sheet No. 1.3 cancelling Volume 1, 2nd Revised Sheet No. 1.3
Volume 2, Original Sheet No. 1.4 cancelling Volume 1, 1st Revised Sheet No. 1.4
Volume 2, Original Sheet No. 1.5 cancelling Volume 1, 1st Revised Sheet No. 1.5
Volume 2, Original Sheet No. 1.6 cancelling Volume 1, 1st Revised Sheet No. 1.6
Volume 2, Original Sheet No. 1.7 cancelling Volume 1, 1st Revised Sheet No. 1.7
Volume 2, Original Sheet No. 1.8 cancelling Volume 1, 1st Revised Sheet No. 1.8
Volume 2, Original Sheet No. 1.9 cancelling Volume 1, 1st Revised Sheet No. 1.9
Volume 2, Original Sheet No. 1.10 cancelling Volume 1, 1st Revised Sheet No. 1.10
Volume 2, Original Sheet No. 1.11 cancelling Volume 1, 1st Revised Sheet No. 1.11
Volume 2, Original Sheet No. 1.12 cancelling Volume 1, 1st Revised Sheet No. 1.12
Volume 2, Original Sheet No. 1.13 cancelling Volume 1, 1st Revised Sheet No. 1.13
Volume 2, Original Sheet No. 1.14 cancelling Volume 1, 1st Revised Sheet No. 1.14
Volume 2, Original Sheet No. 1.15 cancelling Volume 1, 1st Revised Sheet No. 1.15
Volume 2, Original Sheet No. 1.16 cancelling Volume 1, 1st Revised Sheet No. 1.16
Volume 2, Original Sheet No. 1.17 cancelling Volume 1, Original Sheet No. 1.17
Volume 2, Original Sheet No. 1.18
Volume 2, Original Sheet No. 1.19
Volume 2, Original Sheet No. 3 cancelling Volume 1, Original Sheet No. 3
Volume 2, Original Sheet No. 19 cancelling Volume 1, Original Sheet No. 19
Volume 2, Original Sheet No. 19.1 cancelling Volume 1, Original Sheet No. 19.1
Volume 2, Original Sheet No. 20 cancelling Volume 1, 1st Revised Sheet No. 20
Volume 2, Original Sheet No. 20.1 cancelling Volume 1, 1st Revised Sheet No. 20.1
Volume 2, Original Sheet No. 20.2 cancelling Volume 1, 1st Revised Sheet No. 20.2
Volume 2, Original Sheet No. 20.3 cancelling Volume 1, 1st Revised Sheet No. 20.3
Volume 2, Original Sheet No. 20.4 cancelling Volume 1, Original Sheet No. 20.4
Volume 2, Original Sheet No. 20.5
Volume 2, Original Sheet No. 24 cancelling Volume 1, Original Sheet No. 24
Volume 1, Original Sheet No. 24.1 is cancelled
Volume 1, Original Sheet No. 25 is cancelled
Volume 2, Original Sheet No. 34 cancelling Volume 1, Original Sheet No. 34
Volume 2, Original Sheet No. 34.1 cancelling Volume 1, Original Sheet No. 34.1
Volume 2, Original Sheet No. 34.2 cancelling Volume 1, Original Sheet No. 34.2
Volume 2, Original Sheet No. 34.3 cancelling Volume 1, Original Sheet No. 34.3

Section 6
Volume 2, Original Sheet No. 1 cancelling Volume 1, 4th Revised Sheet No. 1
Volume 1, 4th Revised Sheet No. 2 is cancelled
Volume 2, Original Sheet No. 2 cancelling Volume 1, Original Sheet No. 2.1

Volume 2, Original Sheet No. 3 cancelling Volume 1, 2nd Revised Sheet No. 3
Volume 1, 2nd Revised Sheet No. 4 is cancelled
Volume 2, Original Sheet No. 4 cancelling Volume 1, 6th Revised Sheet No. 5
Volume 2, Original Sheet No. 4.1
Volume 2, Original Sheet No. 5 cancelling Volume 1, 4th Revised Sheet No. 6
Volume 2, Original Sheet No. 6 cancelling Volume 1, 1st Revised Sheet No. 7
Volume 2, Original Sheet No. 7 cancelling Volume 1, 2nd Revised Sheet No. 8
Volume 2, Original Sheet No. 7.1 cancelling Volume 1, Original Sheet No. 8.1
Volume 2, Original Sheet No. 8 cancelling Volume 1 Original Sheet No. 9
Volume 1, Original Sheet No. 10 is cancelled
Volume 1, Original Sheet No. 11 is cancelled
Volume 2, Original Sheet No. 9 cancelling Volume 1, Original Sheet No. 12
Volume 2, Original Sheet No. 10 cancelling Volume 1, Original Sheet No. 13
Volume 2, Original Sheet No. 11 cancelling Volume 1, 1st Revised Sheet No. 14
Volume 2, Original Sheet No. 12 cancelling Volume 1, Original Sheet No. 15
Volume 2, Original Sheet No. 13 cancelling Volume 1, Original Sheet No. 16
Volume 2, Original Sheet No. 14 cancelling Volume 1, 1st Revised Sheet No. 17
Volume 2, Original Sheet No. 15 cancelling Volume 1, Original Sheet No. 18
Volume 1, Original Sheet No. 19 is cancelled
Volume 1, Original Sheet No. 20 is cancelled
Volume 1, Original Sheet No. 21 is cancelled
Volume 2, Original Sheet No. 16
Volume 2, Original Sheet No. 17
Volume 2, Original Sheet No. 17.1
Volume 2, Original Sheet No. 17.2
Volume 2, Original Sheet No. 17.3
Volume 2, Original Sheet No. 18 cancelling Volume 1, Original Sheet No. 23
Volume 2, Original Sheet No. 19 cancelling Volume 1, Original Sheet No. 24
Volume 2, Original Sheet No. 19.1 cancelling Volume 1, Original Sheet No. 24.1
Volume 2, Original Sheet No. 19.2 cancelling Volume 1, Original Sheet No. 24.2
Volume 2, Original Sheet No. 19.3 cancelling Volume 1, Original Sheet No. 24.3
Volume 2, Original Sheet No. 19.4
Volume 2, Original Sheet No. 19.5
Volume 2, Original Sheet No. 19.6
Volume 2, Original Sheet No. 19.7
Volume 2, Original Sheet No. 20 cancelling Volume 1, 1st Revised Sheet No. 26
Volume 2, Original Sheet No. 20.1
Volume 2, Original Sheet No. 21 cancelling Volume 1, Sub. Original Sheet No. 28
Volume 2, Original Sheet No. 21.1
Volume 2, Original Sheet No. 22
Volume 2, Original Sheet No. 23
Volume 2, Original Sheet No. 24

It is therefore

ORDERED, that the Settlement Stipulation entered into between MDU and Commission Staff, including the attached customer notice, is approved, with the exception of the effective date. The Settlement Stipulation, including attachment, as so revised is incorporated by reference into this Decision and Order the same as if it had been set forth in its entirety herein; and it is

FURTHER ORDERED, that customer bills shall be prorated so that usage prior to December 2, 2003, is billed at the previous rates and usage on and after December 2, 2003, is billed at the new rates; and it is

FURTHER ORDERED, that the tariff revisions set forth above in this Order are approved.

Dated at Pierre, South Dakota, this 17th day of December, 2003.

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: 12/19/03

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

ROBERT K. SAHR, Chairman

GARY HANSON, Commissioner

JAMES A. BURG, Commissioner

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

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

December 22, 2003

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

RECEIVED
DEC 23 2003
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Re: Compliance Natural Gas Rates
Docket No. NG02-011

Dear Ms. Bonrud:

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits the following tariff sheets to be substituted for the same tariff sheets submitted on December 4, 2003 as part of the Settlement Stipulation in the above referenced Docket. The attached tariff sheets reflect corrections of minor errors found by Staff in their review of the compliance tariffs.

- Section No. 3 – Original Sheet No. 28.1
- Section No. 3 – Original Sheet No. 30.3
- Section No. 6 – Original Sheet No. 24

The original and ten (10) copies of this letter and tariffs have been provided to the South Dakota Public Utilities 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,

Tamie A. Aberle
Pricing & Tariff Manager

Attachment

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

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.

(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.

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: _____