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

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

August 26, 2020

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
600 E Boulevard Ave #408
Bismarck, ND 58505-0480

Re: Application and Notice of Change in Natural Gas Rates
Case No. PU-20-___

Montana-Dakota Utilities Co. (Montana-Dakota) herewith submits its Application and Notice to increase its rates for natural gas service in North Dakota. Montana-Dakota submits this Letter of Transmittal and its Application and Notice with Appendices A and B, Testimony and Exhibits, and Statements supporting an increase in Montana-Dakota's rates for natural gas service. This filing is made in accordance with Title 49 of the North Dakota Century Code and the rules and regulations promulgated by the North Dakota Public Service Commission.

Montana-Dakota will prove by competent evidence that its existing natural gas rates do not allow Montana-Dakota to fully recover the cost of providing gas service to its North Dakota customers; therefore, the current rates are unjust, unreasonable, and not compensatory.

The primary reason for the increase in rates is the increased investment in distribution facilities to improve system safety and reliability and the depreciation and taxes associated with the increase in investment.

Authorization of the requested increase in revenues will provide Montana-Dakota a reasonable opportunity to earn a fair rate of return for its North Dakota natural gas operations.

Montana-Dakota proposes a total annual increase of $8,972,496 or 7.8 percent, based on a 2021 test year. The proposed change in rates will affect customer classes as follows:

Customer Class	Revenue Increase $	Revenue Increase %
Residential	$ 7,330,415	12.5%
Firm General	1,480,594	3.1%
Air Force Delivery	29,382	2.3%
Small Interruptible	97,304	2.5%
Large Interruptible	34,801	0.9%
Total	$ 8,972,496	7.8%

Please refer all inquiries regarding this filing to:

Mr. Travis Jacobson
Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501
travis.jacobson@mdu.com

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

Paul Sanderson
Evenson Sanderson PC
1100 College Drive, Suite 5
Bismarck, ND 58501
(701) 751-1243
psanderson@esattorneys.com

Mr. Karl A. Liepitz
Assistant General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650
Karl.Liepitz@mduresources.com

The original and seven (7) copies of this Letter of Transmittal, Application and Notice, Appendices, Testimony and Exhibits, and Statements are hereby filed with the North Dakota Public Service Commission. An electronic copy has also been provided.

Montana-Dakota also herewith submits a check for $175,000 pursuant to the requirements of Section 49-05-04 of the North Dakota Century Code.

Pursuant to N.D.C.C § 49-05-06(2), Montana-Dakota is concurrently submitting an Application and Notice for Interim Increase in Natural Gas Rates in the annual amount of $6,893,176 to take effect January 1, 2021.

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

Sincerely,

Garret Senger

Garret Senger
Executive Vice President –
Regulatory Affairs, Customer Service,
and Administration

Attachment

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NORTH DAKOTA

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Establish Increased Rates for Natural Gas Service	))))	Case No. PU-20-___

APPLICATION AND NOTICE

COMES NOW, Montana-Dakota Utilities Co., the Applicant in the above-entitled proceeding (hereafter "Montana-Dakota", "Applicant", or "Company"), and respectfully alleges as follows:

I.

That Montana-Dakota is a Delaware corporation duly authorized to do business in the State of North Dakota as a foreign corporation, and that it is doing business in the State of North Dakota as a public utility.

II.

The Company's Certificate of Incorporation and amendments thereto have previously been filed with the North Dakota Public Service Commission ("PSC" 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.
400 North Fourth Street
Bismarck, North Dakota 58501

IV.

Great Plains Natural Gas Co. (Great Plains), a Division of Montana-Dakota, serves customers in Minnesota and the community of Wahpeton and the surrounding area in North Dakota. In a Settlement in Case Nos. PU-17-490 and PU-17-075 approved by this Commission, the Parties agreed to begin combining all gas operations within North Dakota for reporting purposes, which began in 2018, as a first step to having one North Dakota gas utility operation. In this filing, the Company is proposing to eliminate Great Plains' gas tariff and incorporate the appropriate information into Montana-Dakota's gas tariff.

That the following described rate schedules for Montana-Dakota and Great Plains are presently on file with and approved by the Commission are attached hereto as Appendix A.

Montana-Dakota Utilities Co. - Current Tariffs

Volume No. 7	Description	Rate
5th Revised Sheet No. 1	Table of Contents	
3rd Revised Sheet No. 2	Communities Served	
186th Revised Sheet No. 3	Rate Summary Sheet	
4th Revised Sheet No. 3.1	Rate Summary Sheet	
12th Revised Sheet No. 4	Residential Gas Service	60
10th Revised Sheet No. 7	Air Force	64
1st Revised Sheet No. 7.1	Air Force	64
Original Sheet No. 8	Air Force Distribution System	65
12th Revised Sheet No. 13	Firm General Gas Service	70
2nd Revised Sheet No. 13.1	Firm General Gas Service	70
12th Revised Sheet No. 14	Small Interruptible General Gas Service	71
6th Revised Sheet No. 14.1	Small Interruptible General Gas Service	71
3rd Revised Sheet No. 14.2	Small Interruptible General Gas Service	71
1st Revised Sheet No. 14.3	Small Interruptible General Gas Service	71
13th Revised Sheet No. 15	Optional Seasonal General Gas Service	72
2nd Revised Sheet No. 15.1	Optional Seasonal General Gas Service	72
Original Sheet No. 16-16.1	Firm General Contracted Demand Service	74
Original Sheet No. 17-17.1	Gwinner Pipeline Capacity Reservation	75
1st Revised Sheet No. 24	Transportation Service Rates	81 & 82
11th Revised Sheet No. 24.1	Transportation Service Rates	81 & 82
2nd Revised Sheet Nos. 24.2-24.5	Transportation Service Rates	81 & 82
1st Revised Sheet No. 24.6	Transportation Service Rates	81 & 82
2nd Revised Sheet No. 24.7	Transportation Service Rates	81 & 82
1st Revised Sheet Nos. 24.8-24.9	Transportation Service Rates	81 & 82
9th Revised Sheet No. 27	Large Interruptible General Gas Service	85

Great Plains Natural Gas - Current Tariffs

3rd Revised Sheet No. 3	Interruptible Gas Service – General	71
2nd Revised Sheet No. 3.1	Interruptible Gas Service – General	71
1st Revised Sheet No. 3.2	Interruptible Gas Service – General	71
2nd Revised Sheet No. 5	Interruptible Transportation Service	80
1st Revised Sheet No. 5.1	Interruptible Transportation Service	80
2nd Revised Sheet No. 5.2	Interruptible Transportation Service	80
1st Revised Sheet Nos. 5.3-5.4	Interruptible Transportation Service	80
2nd Revised Sheet No. 5.5	Interruptible Transportation Service	80
1st Revised Sheet Nos. 5.6-5.7	Interruptible Transportation Service	80
3rd Revised Sheet No. 7	Cost of Gas – Natural Gas	88
Original Sheet No. 7.1	Cost of Gas – Natural Gas	88
1st Revised Sheet Nos. 9-9.15	General Terms and Condition	100
Original Sheet No. 9.16	General Terms and Condition	100
1st Revised Sheet Nos. 10-10.1	Gas Meter Testing Program	101
Original Sheet Nos. 11-11.3	Firm Gas Service Main and Service Line Extension Policy	105
Original Sheet Nos. 12-12.1	Interruptible Gas Main and Service Line Extensions Policy	106

V.

That Applicant respectfully submits herewith the following described proposed rate schedules for natural gas service, copies attached hereto as Appendix B, which Applicant proposes to be approved on a final basis in this Case. As further explained in testimony submitted in this case, the entire Great Plains' tariff will be eliminated.

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 North 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 of $8,972,496 based on a 2021 future test period, for gas service rendered to customers in the State of North Dakota. This request for additional revenues amounts to a 7.8 percent increase over current natural gas rates.

VIII.

Filed concurrently with this Application and Notice and its Appendices are supporting Statements, and Direct Testimony and Exhibits of Montana-Dakota's witnesses showing the existing rates are unjust, unreasonable, not compensatory, and that the new rates are just, reasonable, and compensatory.

IX.

Montana-Dakota is submitting an Application and Notice for Interim Increase in Natural Gas Rates in the annual amount of $6,893,176. Montana-Dakota is requesting a waiver of the statutory sixty-day implementation of interim rates pursuant to N.D.C.C § 49-05-06(2) in light of the pandemic and is requesting interim rates to take effect January 1, 2021.

X.

This Application and Notice is submitted in accordance with the provisions of N.D.C.C § 49-05-04 and the rules and regulations promulgated by the Public Service Commission of the State of North Dakota and the filing guideline of the Public Service Commission.

XI.

That, in accordance with N.D.C.C § 49-05-04.1, Montana-Dakota hereby affirms that its future test year forecast is reasonable, reliable, and made in good faith. All basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the Commission to test the appropriateness of the forecast. The accounting treatment that has been applied to anticipated events and transactions in the forecast is the same as the accounting treatment to be applied in recording the events once they have occurred.

Dated this 26th day of August 2020.

MONTANA-DAKOTA UTILITIES CO.

By: Garret Senger
Garret Senger
Executive Vice President -
Regulatory Affairs, Customer Service,
and Administration

STATE OF NORTH DAKOTA)
) :ss
COUNTY OF BURLEIGH)

Garret Senger, being first duly sworn, deposes and says that he is the Executive Vice President - Regulatory Affairs, Customer Service, and Administration of Montana-Dakota Utilities Co. that he has read the foregoing Application and Notice, knows the contents thereof, and that the same is true and correct to the best of his knowledge, information, and belief.

Dated this 26th day of August 2020.

By: Garret Senger

Garret Senger
Executive Vice President –
Regulatory Affairs, Customer
Service, and Administration

Subscribed and sworn to before me this 26th day of August 2020.

TERESE M BIRNBAUM
NOTARY PUBLIC
STATE OF NORTH DAKOTA
MY COMMISSION EXPIRES DEC. 30, 2023

Terese M. Birnbaum

Terese M. Birnbaum, Notary Public
Burleigh County, North Dakota
My Commission Expires: 12/30/2023

OF COUNSEL:

Mr. Paul Sanderson
Evenson Sanderson PC
1100 College Drive, Suite 5
Bismarck, ND 58501
(701) 751-1243
psanderson@esattorneys.com

Mr. Karl A. Liepitz
Assistant General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650
Karl.Liepitz@mduresources.com

STATE OF NORTH DAKOTA)
) :ss
COUNTY OF BURLEIGH)

I, Garret Senger, Executive Vice President - Regulatory Affairs, Customer Service, and Administration of Montana-Dakota Utilities Co. do hereby certify that the cost statements, working papers, and other supporting data submitted by Montana-Dakota Utilities Co. as a part of its Application and Notice for Authority to Establish Increased Rates for Natural Gas Service with the North Dakota Public Service Commission, or which are maintained by the Company in support of such filed Application and Notice and which purport to reflect the books of the Company, do in fact set forth the results shown by such books.

Dated this 26th day of August 2020.

By: Garret Senger
Garret Senger
Executive Vice President –
Regulatory Affairs, Customer Service,
and Administration

Subscribed and sworn to before me this 26th day of August 2020.

TERESE M BIRNBAUM
NOTARY PUBLIC
STATE OF NORTH DAKOTA
MY COMMISSION EXPIRES DEC. 30, 2023

Terese M. Birnbaum
Terese M. Birnbaum, Notary Public
Burleigh County, North Dakota
My Commission Expires: 12/30/2023

Montana-Dakota Utilities Co.
North Dakota Gas Tariffs – Current

State of North Dakota
Gas Rate Schedule

TABLE OF CONTENTS

COMMUNITIES SERVED

NATURAL GAS SERVICE

Dakota Heartland Region

Apple Valley	Eldridge	Max	Steele
Barlow	Fort Totten	Medina	Surrey
Bismarck*	Garrison	Minot	Tappen
Burlington	Glen Ullin	New Rockford	Turtle Lake
Carrington	Grafton	New Salem	Underwood
Cavalier	Jamestown	Park River	Valley City
Cleveland	Langdon	Riverdale	Walhalla
Dawson	Lincoln	Ruthville	Washburn
Des Lacs	Linton	Sandborn	Wilton
Devils Lake	Mandan	Sheyenne	Locations near Hankinson/Fairmont

Badlands Region

Alexander	Gladstone	Palermo	Stanley
Arnegard	Golva	Ray	Taylor
Beach	Hebron	Regent	Tioga
Belfield	Killdeer	Rhame	Trenton
Berthold	Lefor	Richardton	Watford City
Bowman	Lignite	Ross	Wheelock
Dickinson*	Marmarth	Sentinel Butte	White Earth
East Fairview	Mott	Springbrook	Williston
Epping	New England	South Heart	

PROPANE SERVICE

Badlands Region

Hettinger

*Designates Region Office

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

State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	$0.6860 per day	$0.000	$3.240	$3.240
Air Force Rate 64	7				
Minot Air Force Base		$2,000.00 per month			
PAR Site		$175.00 per month			
Firm Service			$0.329	$3.240	$3.569
Interruptible Service - PAR			$0.177	$2.348	$2.525
Interruptible Service - MAFB			$0.177	$2.152	$2.329
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.70 per day			
Meters rated > 500 cubic feet		$2.05 per day	$0.811	$3.240	$4.051
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$190.00 per month	$1.063	$2.348	$3.411
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		$0.70 per day			
Meters rated > 500 cubic feet		$2.05 per day	$0.811	$1.751	$2.562
Contracted Demand Service Rate 74	16		(Demand		
Meters rated < 500 cubic feet		$0.70 per day	Charge)	(Capacity Charge)	$10.680
Meters rated > 500 cubic feet		$2.05 per day	$6.510	(COG/Dk)	$1.911
Transportation Service	24				
Small Interruptible Rate 81		$190.00 per month			
Maximum			$0.668		$0.668
Minimum			$0.102		$0.102
Large Interruptible Rate 82		$1,500.00 per month			
Maximum			$0.231		$0.231
Minimum			$0.061		$0.061
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$1,500.00 per month	$0.718	$2.348	$3.066
Residential Propane Rate 90	32	$0.6860 per day	$0.000	$4.169	$4.169
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		$0.70 per day			
Meters rated > 500 cubic feet		$2.05 per day	$0.811	$4.169	$4.980

Date Filed: July 8, 2020

Effective Date: Service rendered on and after August 1, 2020

Issued By: Travis R. Jacobson
Director - Regulatory Affairs

Case No.: PU-20-008

Montana-Dakota Utilities Co.

A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Miscellaneous Charges	Amount
Late Payment	1% per month
Returned Check	$15.00 per check
Reconnection charge after termination for nonpayment -During normal business hours -After normal business hours	 See Rate 100 ¶21 Current service labor rate per hour
Reconnection charge after termination for causes defined in Rate 100 ¶22 -During normal business hours -After normal business hours	 $30.00 Current service labor rate per hour
Reconnection charge applicable to seasonal or temporary customers -During normal business hours -After normal business hours	Basic Service Charge applicable during the period while service was not being used. Minimum- $30.00 Minimum- Current service labor rate per hour
Reconnection charge applicable to transportation customers when remote data acquisition equipment must be reinstalled	$160.00

Date Filed: October 5, 2018

Effective Date: Service rendered on and after December 1, 2018

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.: PU-17-295

RESIDENTIAL GAS SERVICE Rate 60

Availability:

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

Rate:

Basic Service Charge:	$0.6860 per day
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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AIR FORCE Rate 64

Availability:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

Rate:

Basic Service Charge:	
Minot Air Force Base	$2,000.00 per month
Perimeter Acquisition Radar (PAR) Site	$175.00 per month
Distribution Delivery Charge:	
Firm Service	$.329 per dk
Interruptible Service	$.177 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If the 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 Service distribution delivery charge and cost of gas rates 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 $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.

2. CONTRACT – Terms of service other than the rate shall be specified in contracts between Minot Air Force Base, and PAR and the Company.

3. The foregoing schedule is subject to Rates 100 through 124 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 North Dakota
Gas Rate Schedule

AIR FORCE Distribution System Rate 65

Availability:

Operation and maintenance of the Minot Air Force Base distribution system near Minot, North Dakota.

Rate:

Distribution System Operation and Maintenance Fee	\$35,500.00 per month (months 1-36) \$38,000.00 per month (month 37 forward)
Amortization of Purchase Price	\$(3,053.00) per month

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.

General Terms and Conditions:

1. Terms of service including transition period fees shall be specified by contract between Minot Air Force Base and the Company.

2. The amortization on purchase price amount shall be a credit to the Minot Air Force Bill each month.

3. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: November 3, 2006 **Effective Date:** October 1, 2008

Issued By: Donald R. Ball
Vice President - Regulatory Affairs **Case No.:** PU-06-470

FIRM GENERAL GAS SERVICE Rate 70

Availability:
In all communities served for all purposes except for resale. See Rate 100, §3, for definition on class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.70 per day
For customers with meters rated over 500 cubic feet per hour	$2.05 per day
Distribution Delivery Charge:	$0.811 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.13, or any amendments or alterations thereto.

Cost of Gas:
The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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:

The foregoing schedule is subject to Rates 100 through 124 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 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 100,000 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 interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$190.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$1.063 per dk	$0.668 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the Cost of Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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.11.

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.

3. AGREEMENT – Customer will be required 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Reserved for Future Use

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served 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	$0.70 per day
For customers with meters rated over 500 cubic feet per hour	$2.05 per day
Distribution Delivery Charge:	$0.811 per dk
Cost of Gas:	
Winter- Service rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Service rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.13, or any amendments or alterations thereto.

Cost of Gas:

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

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

General Terms and Conditions:

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

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Availability:

In all communities served applicable to non-residential customers with standby natural gas generators and, available on an optional basis to, customers qualifying for service under the interruptible service tariffs that have requested, and received approval from the Company, for gas service under this rate.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.70 per day
For customers with meters rated over 500 cubic feet per hour	$2.05 per day
Distribution Demand Charge:	$6.51 per Dk per month of billing demand
Capacity Charge per Monthly Demand Dk:	Determined Monthly – See Rate Summary Sheet for Current Rate
Cost of Gas – Commodity per Dk:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge, Distribution Demand Charge, and Capacity 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

Cost of Gas:

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

Metering Requirements:

1. Service provided for under tariff must be separately metered from customer's other gas services.

2. Remote data acquisition equipment (telemetering equipment) may be required by the Company for a single customer installation for daily measurement.

3. Customer may be required, upon consultation with the Company, to contribute towards any additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

4. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

General Terms and Conditions:

1. The customer agrees to contract for service under the Firm General Demand Rate 74 for a minimum period of one year.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations therefore or additional rules and regulations promulgated by the Company under the laws of the state.

GWINNER PIPELINE CAPCACITY RESERVATION CHARGE Rate 75

Availability:

To customers provided natural gas service either directly or through another connection with the Company's pipeline interconnecting with the Alliance Pipeline near Milnor, North Dakota and running through Ransom and Sargent Counties to the Bobcat Company's facility located near Gwinner, North Dakota (Gwinner Pipeline).

Applicability:

Customers requesting natural gas service where service must be provided off the Gwinner Pipeline shall contract for capacity required to serve their annual requirements. The Reservation Charge shall be in addition to all other charges applicable under the otherwise applicable rate schedule 60, 70, 71, 72, 81, 82 or 85.

Capacity Reservation Charge:

Residential Customers provided Service Under Rate 60	$0.8712 per day
All other Customers	$26.50 per maximum daily quantity reservation

Minimum Bill:

Capacity Reservation 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.12, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract except for residential customers that will be assessed the daily charge above. All other customers will specify a contract quantity based on the maximum daily quantity required. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

GWINNER PIPELINE CAPCACITY RESERVATION CHARGE Rate 75

General Terms and Conditions:

1. The customer agrees to contract for service under the Gwinner Pipeline Capacity Reservation Charge Rate 75 for a minimum period of one year.

2. Service under any other rate schedule is not available to customers served through the Gwinner Pipeline without a reservation for capacity on the Gwinner Pipeline.

3. Any main or service line extension necessary to provide service to the Customer shall be subject to the Firm Gas Service Extension Policy Rate 120 or Interruptible Service Extension Policy Rate 119.

4. The foregoing schedule is subject to the requirements set forth under the otherwise applicable rate schedule for natural gas service and Rates 100 through 124, including 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 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:

<u>Small Interruptible General Gas Transportation Service Rate 81:</u>
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 100,000 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.

<u>Large Interruptible General Gas Transportation Service Rate 82:</u>
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually metered at a single delivery point, 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:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71 or Rate 85, the Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived.

Basic Service Charge:

Rate 81	$190.00 per month
Rate 82	$1,500.00 per month

	Rate 81	Rate 82
Maximum Rate per dk	$0.668	$0.231
Minimum Rate per dk	$0.102	$0.061

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. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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.11.

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 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 $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. CUSTOMER USE OF NON-DELIVERED VOLUMES - 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 9.b. Gas volumes supplied by Company will be charged at Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas). The Company is under no obligation to notify customer of non-delivered volumes.

7. REPLACEMENT OR SUPPLEMENTAL SALES SERVICE - 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.

8. 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 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.

   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.20.

9. DAILY IMBALANCE:
   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.

b. In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.

c. 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. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

c. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Averages Prices" published by Gas Daily for CIG Rockies and Northern Ventura during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

11. METERING REQUIREMENTS:

a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards an additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made

c. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

12. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper or agent shall advise the Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC timelines, of the dk requirements customer has requested to be delivered at each delivery point 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.

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

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.13, or any amendments 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. The foregoing schedule is subject to Rates 100 through 124 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 for all interruptible general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually as metered at a single delivery point. 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.

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

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge:	$1,500.00 per month	
Distribution Delivery Charge:	Maximum $0.718 per dk	Minimum $0.231 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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.11.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain 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.

3. AGREEMENT – Customer will be required 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 90 days prior to the end of the initial term. Absent execution of 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company, prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Reserved for Future Use

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

State of North Dakota
Gas Rate Schedule

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 billing period from November 1 through May 1. Service provided under the Company's Firm General Service Rates 70 and 92 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 Firm General Service Rates 70 and 92 beginning with the first billing cycle starting November 1 through the billing cycle ending May 1. The DDSM adjustment will be applied on a real-time basis as a surcharge or credit on all rate schedules to which the DDSM is applicable to the customers' bills issued each month during the weather adjustment period of November 1 through May 1.

DDSM Adjustment Calculation:

The DDSM Adjustment shall be determined for each customer taking service under Firm General Services Rate 70 or 92. 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. The resulting product shall be multiplied by the applicable Distribution Delivery Charge rate per dk.

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

Where:

$DDSM_i$	=	Distribution Delivery Stabilization Adjustment
i	=	Customer served under Rate Schedules 70 or 92
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

Date Filed: November 9, 2015

Effective Date: Service rendered on and after December 1, 2015

Issued By: Tamie A. Aberle
Director – Regulatory Affairs

Case No.: PU-15-090

DISTRIBUTION DELIVERY STABILIZATION MECHANISM Rate 87

Definitions:

Heating Degree Days	-	The deviation between the average daily temperatures and 60 degrees Fahrenheit.
Normal Degree Days	-	The heating degree days based on the 30-year average actual degree days.
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. Firm General Service Rate Code 700 = 0.03184 Firm General Service Rate Code 701 = 0.74281 Firm General Service Rate Code 920 = 0.01994 Firm General Service Rate Code 921 = 2.38427
Actual Degree Days	-	The actual degree days reported by the National Weather Service Stations for applicable service areas in North Dakota.

1. **Applicability:**
   This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of natural gas supply, (b) amortization of the Unrecovered Purchased Gas Cost Account and (c) grain drying margin sharing.

2. **Effective Date and Limitation on Adjustments:**
   (a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.

   (b) Montana-Dakota shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least twenty-five (25) cents per dk. The adjustment to be effective October 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
   (a) The monthly COG shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing. 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. 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.

   (b) The COG 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 COG 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 adjusted to reflect losses.

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

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

(3) Demand costs for firm general contracted demand customers shall be stated on the incremental MDDQ basis.

(4) 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.

(5) 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.

(6) 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 COG shall be applied to each of Montana-Dakota's rate schedules recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

4. Surcharge Adjustment:

(a) All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on October 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 Purchased Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Account (Account 191), as calculated in accordance with Subsection 5(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in the COG by reason of the twenty-five 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.

(4) Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

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

(b) (1) The amount to be included in Account 191 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 supplier's 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 COG.

(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 Account 191 for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in Account 191 at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. 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 Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 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. 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 Account 191 specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Account 191 specified in Subsection 5(a)(4).

6. Grain Drying Margin Sharing Mechanism:
At the time of each surcharge adjustment, pursuant to Paragraph 4, the Company will compute a credit to Rates 60, 70, 72, and 74 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service rates as established in Case No. PU-13-803, including prior period over or under collected balances.

7. Time and Manner of Filing:

(a) Montana-Dakota shall file to change the COG at least 20 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised COG sheets identifying the amounts of the adjustments and the resulting currently effective COG rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant pipeline tariff sheets supporting costs claimed.

RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.6860 per day
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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed:	October 5, 2018	**Effective Date:**	Service rendered on and after December 1, 2018
Issued By:	Tamie A. Aberle Director – Regulatory Affairs	**Case No.:**	PU-17-295

RESIDENTIAL PROPANE SERVICE Rate 90

Reserved for Future Use

State of North Dakota
Gas Rate Schedule

FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

For the community of Hettinger 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	$0.70 per day
For customers with meters rated over 500 cubic feet per hour	$2.05 per day
Distribution Delivery Charge:	$0.811 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of propane as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane 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.

FIRM GENERAL PROPANE SERVICE Rate 92

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed:	October 5, 2018	**Effective Date:**	Service rendered on and after December 1, 2018
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1. **Availability:**
This rate schedule constitutes a Cost of Gas (COG) provision and specifies the procedure to be utilized to adjust the rates for propane gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of propane supply, (b) amortization of the Unrecovered Purchased Cost of Gas Account and (c) grain drying margin sharing.

2. **Effective Date and Limitation on Adjustments:**
(a) The effective dates of the COG shall be service rendered on and after the first day of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file to reflect changes in its average cost of propane supply only when the amount of such change in COG is at least twenty-five (25) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
(a) The monthly COG shall reflect changes in Montana-Dakota's cost of propane supply as compared to the cost of propane supply approved in its most recent COG filing. The cost of propane supply shall include, but not be limited to, all commodity and transportation charges incurred by Montana-Dakota for such propane supply.

(b) The propane commodity cost shall reflect all commodity related propane costs estimated to be incurred for the month the COG will be in effect and estimated dk purchases.

The unit cost per dk for the month shall be the commodity costs divided by estimated dk purchases for the month.

4. **Surcharge Adjustment:**
All propane sales schedules shall be subject to a Surcharge Adjustment to be effective on May 1 each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Cost of Gas 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 Purchased Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Account (Account 191), as calculated in accordance with Subsection 5(b) are:

(1) Charges for propane supply which Montana-Dakota is unable to reflect in the COG by reason of the twenty-five cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for propane supplies that were paid during any period after the effective date of the most recent approved rates, but not yet included in propane sales rates.

(3) Carrying charges or credits.

(b)

(1) The amount to be included in Account 191 in order to reflect the items specified in Subsections 5(a)(1) and (2) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's propane supply.

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

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each propane rate schedule. The resulting amounts shall be reflected in an Account 191 for each rate schedule.

Montana-Dakota will calculate carrying charges on the amounts in Account 191 as follows:

Each month, Account 191 shall be debited (on a debit balance) or credited (on a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

(i) The balance on 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 three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The carrying charges shall be accrued in a supplementary Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 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. 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 Account 191 specified in Subsections 5(a)(1) and (2) and the amounts in the supplementary Account 191 specified in Subsection 5(b)(2)(ii).

6. Grain Drying Margin Sharing Mechanism:
At the time of each surcharge adjustment, pursuant to Paragraph 4 of Rate 88, the Company will compute a credit to Rates 90 and 92 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service rates as established in Case No. PU-13-803, including prior period over or under collected balances.

7. Time and Manner of Filing:

(a) Montana-Dakota shall file each COG at least 10 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised COG sheets identifying the amounts of the adjustments and the resulting currently effective COG rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant material supporting costs claimed.

TABLE OF CONTENTS
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 Service Commission of North 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 Service Commission of the State of North 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 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.

EXCESS FLOW VALVE – Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.

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

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, 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 OBLIGATION:**

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 person 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 required to make a deposit as required by the Company.

2. SERVICE AVAILABILITY – Gas will normally be delivered at standard pressures of four to six ounces, dependent on the service territory where the gas service is being delivered. Delivery of gas service at pressures greater than the standard operating pressure may be available and will require a consultation with the Company to determine availability.

3. 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 ensure that such

equipment will conform to the Company's ability to adequately serve such installations with gas.

4. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises Monday through Friday, 8:00 a.m. to 5:00 p.m., unless an emergency requires access outside of these hours, for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

5. 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.

6. 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.

7. 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 or permits.

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

9. TERMINATION OF 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.

10. 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.

11. QUALITY OF GAS – The gas tendered to the Company shall conform to the applicable quality specifications of the transporting Pipeline's tariff.

IV. **LIABILITY**

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

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. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on the customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues and appliances on the customer's side of the point of delivery.

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, 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 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 authorization 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 with separate cooking facilities. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes with separate meters and sorority and fraternity houses. In addition, auxiliary buildings on the same premise as the living quarters when used for residential purposes may be served on the residential rate. This is not an all-inclusive list.

   (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 salons, 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 Homes 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.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with the following criteria:
   (a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   (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 be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. 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.

   A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.

   Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for twelve months, provided prompt payment record 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) Interruptible sales and transportation service customers agree to provide the cost of the installation of remote data acquisition equipment; as required, to the Company before service is implemented as provided for in the applicable rate schedule.

(c) 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, provided the equipment shall not interfere with such delivery or with the Company's meter.

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 (60ºF). 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 <u>Supercompressibility Factors for Natural Gas</u> 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, supercompressibility calculation. For handbilled accounts, application of supercompressibility factors will be waived on monthly-billed volumes of 250 dk or less.

Local sales base pressure is defined as four to six ounces (depending on service area) per square inch gauge pressure plus local average atmospheric pressure.

10. BILLING ADJUSTMENTS –
    (a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as Residential Service Rates 60 or 90, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as non-residential (gas service provided under all rate schedules other than Rates 60 or 90), the Company may adjustment back and rebill the bills in error for a period not to exceed six years.

    (d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and

refund the customer the amount of the overbilled for a period not to exceed six years from the date of payment.

11. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from Highest to Lowest:
    (a) Priority 1 – Firm sales services.
    (b) Priority 2 – Small interruptible sales at the maximum rate on a pro rata basis.
    (c) Priority 3 – Small interruptible sales at less than the maximum rate from the highest rate to the lowest rate on the pro rata basis where equal rates are applicable among customers.
    (d) Priority 4 – Large interruptible sales at the maximum rate on a pro rata basis.
    (e) Priority 5 – Small interruptible transportation services from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    (f) Priority 6 – Large interruptible transportation services from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    (g) Priority 7 – Gas scheduled to clear imbalances.

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

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

12. EXCESS FLOW VALVE – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.

13. 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 percent per month will be applied to any past due balance, 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.

14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for any check for any reason not honored by customer's bank.

15. 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 customer's 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.

16. 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 fumes.

(3) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

(4) Maintenance or repair of Company-owned facilities on the customer's premises.

(4) Pilot relights necessary due to an interruption in gas service deemed to be the Company's responsibility.

(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) High bills or inadequate service complaints.

(3) Location of underground Company facilities for contractors, builders, plumbers, etc.

17. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.

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.

To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

18. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service disconnected shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, or telephone call to the Company's Customer Service Center. Saturdays, Sundays and legal holidays are not considered business days.

19. 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.

20. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER – A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee as follows:

    Residential - The Basic Service Charge applicable during the period service was not being used and a charge of $30.00. The minimum will be based on standard overtime rates for reconnecting service after normal business hours.

    Non-Residential – The Basic Service Charge applicable during the period while service was not being used. However, the reconnection charge applicable to seasonal business concerns such as irrigation, swimming facilities, grain drying and asphalt processing shall be the Basic Service Charge applicable during the period while service was not being used less the Distribution Delivery Charge revenue collected during the period in-service for usage above the annual authorized usage by rate class (Small Firm General = 188 dk; Large Firm General = 1272 dk; Small Firm General Propane = 173 dk; Large Firm General Propane = 2089 dk; and Small Interruptible = 6227 dk). A reconnection fee of $30.00 will also apply to reconnections. The minimum will be based on standard overtime rates for reconnecting service occurring after normal business hours.

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

21. 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. For calls received after 12:00 p.m. on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

22. 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.

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

    (c) For failure of the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

    (d) 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.

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

(a) Examples of unauthorized use of service includes but is not limited to, tampering or unauthorized reconnection by the following methods:
   (1) Bypass piping around meter.
   (2) Bypass piping installed in place of meter.
   (3) Meter reversed.
   (4) Meter index disengaged or removed.
   (3) Service or equipment tampered with or piping connected ahead of meter.
   (4) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
   (5) Gas being used after service has been discontinued by the Company. 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) In the event that there has been unauthorized use of service, customer shall be charged for:
   (1) Time, material and transportation costs used in investigation.
   (2) Estimated charge for non-metered gas.
   (3) On-premise time to correct situation.
   (4) Any damage to Company property.
   (5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.

(c) Reconnection of Service:
   Gas Service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service, and paid any service charges which are due, including:
   (1) All delinquent bills, if any.
   (2) The amount of any Company revenue loss attributable to said tampering.
   (3) Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in number 20.b above.
   (4) Reconnection fee applicable.
   (5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

22. BILL DISCOUNT FOR QUALIFYING EMPLOYEES – A bill discount may be available for residential use only in a single family unit served by Montana-Dakota to qualifying retirees of MDU Resources and its subsidiaries. The bill shall be computed at applicable rate and the amount reduced by 33 1/3 percent.

23. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:

    Rate 119 – Interruptible Gas Service Extension Policy
    Rate 120 – Firm Gas Service Extension Policy
    Rate 124 –Replacement, Relocation and Repair of Gas Service Lines

Reserved for Future Use

GAS METER TESTING PROGRAM Rate 105

Applicability:
This rate schedule specifies the protocol to be followed for the testing of gas meters in compliance with Sections 69-09-01-14 and 69-09-01-16 of the North Dakota Century Code.

Testing Process for New Meters

1. Meter supplier(s) shall provide test data for all new meters.

2. A sampling of 5% of new meter lots received will be tested at full load and light load. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or the shipment shall be returned to the manufacturer.

Testing Process for Meters in Service

1. This meter test schedule shall not apply to meters larger than 650 cubic feet per hour (cfh). Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.

2. All active meters, 650 cfh and smaller, will be combined into a single random test program. The population of meters shall come from the states of North Dakota, Montana, South Dakota, and Wyoming.

3. At the time the random selection is made, meters more than ten years old and active meters that have not been tested in the last ten years will be placed into an installation class defined model installation date lot (lot) to be part of a random population for testing.

4. All active meters will be assigned to lots on the basis of installation date. Meters shall be divided into lots based on manufacturer, type, and last install date in five year groups. The minimum number of samples taken from each lot will be as specified by Military Standard 414, Sample Procedures and Tables for Inspection by Variables for Percent Defective, inspection level IV with specification limits of + 2.0%.

GAS METER TESTING PROGRAM Rate 105

5. The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.

6. Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable quality level of 15%. The following actions will be taken based on the test results:

   a. A meter for which the sample is satisfactory will remain in service.

   b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.

   c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% of the sample registers over 102%

      i. If evaluation determines the group is homogeneous, then the entire group will be removed.

      ii. If group is not homogeneous and a subset of the group is found defective, that subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.

Reporting
Montana-Dakota shall file reports of its meter test results by December 1 for the meter testing conducted between June 30 of the previous year and July 1.

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 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, service line(s), regulators, meters, 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. Remote data acquisition equipment cost's shall be subject to the terms and conditions specified in the applicable interruptible service rate schedule.

   (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, or letter of credit, 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 shall pay the Company for such contribution requirement, or

   (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.

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'' actual throughput.

ii. Customers who have posted a bond or letter of credit, will be notified of any reduction in surety 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 (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.

(d) The Company and customer may enter into a contract providing for a refund mechanism based on customer meeting identified minimums on the basis of specific extension characteristics.

FIRM GAS SERVICE EXTENSION POLICY Rate 120

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm sales 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 ¶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)/LARR

   where: LARR = Levelized Annual Revenue Requirement Factor of 13.807%

4. Cost of the extension shall include the gas main extension(s), valves, service line(s), any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs up to, and including, the riser.

   The service line is that portion of the gas service extending from the gas 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 ¶ 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. A minimum annual charge set forth in an agreement between customer and Company, or
      iv. Customer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state,

or letter of credit, 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 exits in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement.

(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 volumes 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. Customers who have posted a bond or letter of credit, will be notified of any reduction in surety 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 a project consisting of 10 or more customers requesting service when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. If the Company and customers mutually agree that the project will be funded through a Surcharge, the project will be designated an expansion area and the Surcharge will be applicable to all connections within the expansion area. 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 in a five-year period.

(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 a mobile home court, in which a developer is installing roads, utilizes, 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 ¶A.3.

(b) The contribution shall be made by:

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

ii. Developer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state or, letter of credit 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.

FIRM GAS SERVICE EXTENSION POLICY Rate 120

(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. Developers who have posted a bond, or a letter of credit will be notified of any reduction in surety 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.

REPLACEMENT, RELOCATION
AND REPAIR OF GAS SERVICE LINES Rate 124

1. 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.), the customer shall be charged for on the basis of direct costs incurred by the Company.

2. 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 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.

3. 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 the Firm Gas Service Extension Policy - Rate 120.

Great Plains Natural Gas Co.
North Dakota Gas Tariffs – Current

TABLE OF CONTENTS

State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/dk
Firm Gas Service - General Rate 65	2	$3.50 per month	First 10 dk	$1.0720	$2.3219	$3.3939
			Over 10 dk	0.8220		3.1439
Interruptible Gas Service - General Rate 71	3	$3.50 per month	(Maximum)			(Maximum)
			First 400 dk	$1.0160	$2.0610	$3.0770
			Next 2,600 dk	0.7675		2.8285
			Over 3,000 dk	0.6140		2.6750
Transportation Service Rate 80	5	$3.50 per month	(Maximum)			(Maximum)
			First 400 dk	$1.0160		$1.0160
			Next 2,600 dk	0.7675		0.7675
			Over 3,000 dk	0.6140		0.6140

FIRM GAS SERVICE – GENERAL Rate 65

Availability:

Service under this schedule is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. See Rate 100 §III.2 for availability of firm gas service. Service under this rate shall not be subject to curtailment or interruption.

Rate:

Basic Service Charge:		$3.50 per month
Distribution Delivery Charge:		
First	10 dk/month	$1.072 per dk
Excess of	10 dk/month	$0.822 per dk
Cost of Gas:		Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge

Cost of Gas:

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

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.13, or any amendments or alterations thereto.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

INTERRUPTIBLE GAS SERVICE – GENERAL Rate 71

Availability:

Service under this schedule is available on an interruptible basis to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk and who have satisfied Great Plains Natural Gas Co. of their ability and willingness to discontinue the use of said gas during the period of curtailment or interruption, by the use of standby facilities or suffering plant shut-down. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in firm service agreement. The firm service volumes are subject to available capacity. Customer's firm load shall be billed at Firm Gas Service – General Rate 65. For interruptible purposes, the maximum daily firm requirements shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:			$3.50 per month	
Distribution Delivery Charge:			Maximum	Minimum
First	400	dk/month	$1.0160 per dk	$0.130 per Dk
Next	2,600	dk/month	$0.7675 per dk	$0.130 per Dk
Excess of	3,000	dk/month	$0.6140 per dk	$0.130 per Dk
Cost of Gas:			Determined Monthly – See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge

Cost of Gas:

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

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.13, or any amendments or alterations thereto.

INTERRUPTIBLE GAS SERVICE – GENERAL 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 rate, 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.11.

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 Gas Service – General Rate 65 (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.

3. AGREEMENT – Customer will be required 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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.

INTERRUPTIBLE GAS SERVICE – GENERAL Rate 71

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(s) caused by customer's action.

5. METERING REQUIREMENTS –
   a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

   b. Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

      Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed:	January 11, 2019	**Effective Date:**	Service rendered on and after February 1, 2019
Issued By:	Tamie A. Aberle Director – Regulatory Affairs	**Case No.:**	PU-17-075 & PU-17-490

INTERRUPTIBLE TRANSPORTATION SERVICE Rate 80

Availability:

Service under this rate schedule is available on an interruptible basis to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk and who have satisfied Great Plains Natural Gas Co. of their ability and willingness to discontinue the use of said gas during the period of curtailment or interruption, by the use of standby facilities or suffering plant shut-down. This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through the Company's distribution facilities. To obtain transportation service, a customer must meet the general terms and conditions of service provided hereunder and enter into a gas transportation agreement upon request of the Company.

Rate:

Basic Service Charge: $3.50 per month

Distribution Delivery Charge:			Maximum	Minimum
First	400	dk/month	$1.0160 per dk	$0.130 per Dk
Next	2,600	dk/month	$0.7675 per dk	$0.130 per Dk
Excess of	3,000	dk/month	$0.6140 per dk	$0.130 per Dk

Customers shall pay Basic Service Charge plus a negotiated rate not to exceed the maximum rate or less than the minimum rate specified above.

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.13, or any amendments or alterations thereto.

General Terms and Conditions:

1. CRITERIA FOR SERVICE: In order to receive transportation service, customer must qualify under the Company's applicable natural gas transportation service rate 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. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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 under the Firm Gas Service – General Rate 65 (distribution delivery charge and cost of gas). 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.11.

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 customer's behalf, shall be billed at the Firm Gas Service – General Rate 65 (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.

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 charged at the Firm Gas Service – General Rate 65 (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 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.

   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.

8. DAILY IMBALANCE – 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.

   In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.

   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.

9. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

   a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

   Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 9(c).

   b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 9(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Average Prices" published by Gas Daily for Emerson, Manitoba during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

10. METERING REQUIREMENTS:

a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

11. DAILY NOMINATION REQUIREMENTS:

a. Customer or customer's shipper or agent shall advise Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC time lines, of the dk requirements customer has requested to be delivered at each delivery point 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.

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

12. 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.

13. 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.

14. 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.13, or any amendments or alterations thereto.

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

16. The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

1. **Applicability:**
This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under Great Plains rate schedules in order to reflect: (a) changes in Great Plains' average cost of natural gas supply and (b) amortization of the Gas Cost Reconciliation account.

2. **Effective Date and Limitation on Adjustments:**
(a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.

(b) Great Plains shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least $0.25 per dk. The adjustment to be effective June 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
(a) The monthly COG shall reflect changes in Great Plains' cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing.

(b) Firm Demand - The average cost of demand for Firm Gas Sales shall be computed on the basis of current pipeline rates and contract demand divided by twelve month weather normalized sales volumes applicable for the entire Great Plains' gas system.

(c) Gas Commodity - The average weighted commodity cost, including transportation and other costs associated with the acquisition of gas, from all suppliers for the month the COG will be in effect.

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

4. **Gas Cost Reconciliation (GCR)**
(a) For each twelve-month period ending April 30, a Gas Cost Reconciliation (GCR) will be calculated for each class set forth above. The GCR will be added to each customer class' cost of gas supply for the twelve-month period effective June 1 of each year. This adjustment shall include:

COST OF GAS – NATURAL GAS RATE 88

1. The balance in the (over) under recovered gas cost account as of April 30.
2. The difference between actual and recovered gas costs for each customer class for the twelve months ending April 30. The amount may be an under recovery or (over) recovery.
3. Demand costs recovered from the interruptible sales customers will be credited to the firm general service customers.
4. Any refunds from suppliers of gas or pipeline services.
5. Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

(b) The resulting balance is divided by the projected dk sales for the next twelve months. The GCR adjustment shall be applied to the customers' monthly billings commencing on June 1 and remain in effective for a twelve (12) month period.

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 Service Commission of North 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 Service Commission of the State of North Dakota.

COMPANY – Great Plains Natural Gas 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.

EXCESS FLOW VALVE - Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.

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

INTERRUPTIBLE CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency that will cease the use of natural gas or transportation service when deemed necessary by Company.

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

NOMINATION – The daily 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.

2. INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,000,000 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 ensure 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 8 a.m. to 5 p.m. Monday – Friday unless an emergency situation requires access outside of these hours 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.

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, 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 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.

10. QUALITY OF GAS – The gas tendered to the Company shall conform to the applicable quality specifications of the transporting pipeline's tariff.

IV. LIABILITY:

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

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, devices owned, installed or maintained by the customer or leased by the customer from third parties. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues, and appliances on the customer's side of the point of delivery.

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 authorization 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. 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. SERVICE FACILITIES ON CUSTOMER PREMISES – The Company shall furnish, own, and maintain all material and equipment to the outlet side of the meter on the customer's premises. Customer shall pay an installment or connection charge based upon the following rates:

   (a) New Service Line Construction:

      (1) Minimum connecting charge, per meter, covering the cost of service connection, general inspection, and gas turn-on and payable at the time of sign-up is $25.00 for customers with gas input loads up to 400,000 Btu/hour; $50.00 for customers with gas input loads above 400,000 Btu/hour and $100.00 for interruptible customers.

      (2) Service line installation charges shall be based upon the lesser of the Company's labor and material rates or the current cost per foot.

   Length of service line shall be determined by measurement made from customer's property line to stop value on the service riser.

   (b) Additional meters to existing service lines and inactive line connections:

   A $25.00 connection charge covering the cost of service connection, general inspection, and gas turn-on will be collected at time of application from each individual requesting an additional meter to an existing service line or connection to an inactive line.

   (c) Relocation of Existing Meters and Service Lines:

   When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and material rates.

4. TEMPORARY SERVICE – At the discretion of the Company, temporary service may be rendered to a customer's premise. The Company may require the customer to bear the cost of installing and removing the service

in excess of any salvage realized. Advance installation payment may be required prior to installing the service.

The customer shall pay the regular rates applicable to the class of service rendered.

5. 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.

6. 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 Homes 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.

7. 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 and one-half times the estimated amount of one month's average bill.

   (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 be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. 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.

A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.

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

8. 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) Interruptible sales and transportation service customers agree to provide the cost of the installation of remote data acquisition equipment; as required, to the Company before service is implemented as provided in the applicable rate schedule.

9. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be (1) dekatherm (dk), unless otherwise specified. One dk equals 10 therms or 1,000,000 Btu's. Dk 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.

10. 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 (60ºF). 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, supercompressibility calculation.

Local sales base pressure is defined as five ounces per square inch gauge pressure plus local average atmospheric pressure.

11. PRIORITY OF SERVICE – Priority of Service from Highest to Lowest:
    (a) Priority 1 – Firm sales services.
    (b) Priority 2 – Interruptible sales and interruptible transportation services.
    (c) Gas scheduled to clear imbalances.

    Company 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 Company system.

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

12. EXCESS FLOW VALVES – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.

13. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill, or 22 days from date of bill. An amount equal to 1 1/3% per month will be applied to any unpaid balance if not paid by the due 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.

14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for each check charged back to the Company by a bank.

15. 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 customer's 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.

16. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.

    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.

    To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

17. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service disconnected shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, or telephone call to the Company's Customer Service Center. Saturdays, Sundays and legal holidays are not considered business days.

18. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee of $30.00.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a minimum reconnection charge of $160.00 whenever reinstallation of the required 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 $30.00 before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

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 such as tampering with a Company meter, pressure regulator, registration, connections, equipment, seals, procedures or records that result in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service that has been terminated, without the Company's consent.

(a) Examples of unauthorized use of service include the following, but are not limited to:

(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) In the event that there has been unauthorized use of service, customer shall be charged for:

(1) Time, material and transportation costs used in investigation.
(2) Estimated charge for non-metered gas.
(3) On-premise time to correct situation.
(4) Any damage to Company property.
(5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.

(c) Customer service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid all charges as hereinafter set forth in this procedure.

(1) All delinquent bills, if any.
(2) The amount of any Company revenue loss attributable to said tampering.
(3) Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in number 21.b above.
(4) Reconnection fee equal to the Company's minimum service charge.

(5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

22. BILLING ADJUSTMENTS –

(a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

(b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service was provided under Rate 65, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

(c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where service was provided under an interruptible service schedule, the Company may adjustment back and rebill the bills in error for a period not to exceed six years.

(d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and refund the customer the amount of the overbilled.

Applicability:

This rate schedule specifies the protocol to be followed for the testing of gas meters in compliance with Sections 69-09-01-14 and 69-09-01-16 of the North Dakota Century Code.

Testing Process for New Meters

1. Meter supplier(s) shall provide test data for all meters.

2. A sampling of 5% of new meter lots received will be tested at full load and light load. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or shipment shall be returned to the manufacturer.

Testing Process for Meters in Service:

1. This meter test schedule shall not apply to meters larger than 650 cubic feet per hour (cfh). Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.

2. All active meters, 650 cfh and smaller will be combined into a single random test program. Great Plains meters shall be combined with Montana-Dakota Utilities Co. meters for purposes of random sample testing only.

3. At the time the random selection is made, meters more than ten years old and active meters that have not been tested in the last ten years will be placed into an installation class defined model installation date lot to be part of a random population for testing.

4. All active meters rated at 650 CFH and smaller, will be assigned to lots on the basis of installation date. Meters shall be divided into lots based on manufacturer, type, and last install date in five year groups. The minimum number of samples taken from each lot will be as specified by Military Standard 414, Sample Procedures and Tables for Inspection by Variables for Percent Defective, inspection level IV with specification limits of +2.0%.

5. The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.

6. Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable

quality level of 15%. The following actions will be taken based on the test results:

a. A meter for which the sample is satisfactory will remain in service.

b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.

c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% if the sample registers over 102%

    i. If evaluation determines the group is homogeneous, then the entire group will be removed.

    ii. If group is not homogeneous and a subset of the group is found defective, the subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.

Reporting:

Great Plains shall file reports of its meter test results by December 15 for the meter testing conducted for the previous calendar year.

FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105

The Company will install gas main extensions using the following guidelines applicable to firm gas main extensions:

a) The term “main” refers to the facilities that are typically constructed from a border station or regulator station with no particular terminus at a building or structure. Mains are normally installed in streets, alleys, dedicated public ways or dedicated utility easements.

b) Customer refers to customer ultimately taking natural gas service or a developer request to provide natural gas service to residential customers.

c) Cost Participation. Cost participation for firm gas extensions shall be determined as follows:

   i) Extensions 95 Feet or Less – The Company will extend a gas main up to, but not to exceed, 95 feet per home projected to be connected within twelve (12) months from the start of construction where natural gas is the primary fuel used for space heating.

   ii) Extensions over 95 Feet or where natural gas in not the primary fuel used for space heating – The Company may require cost participation if the estimated capital expenditure is not cost justified. The extension will be considered cost justified if the calculated Maximum Allowable Investment equals or exceeds the estimated capital expenditures using the following formula:

   Maximum Allowable Investment (MAI) =

   Annual Basic Service Charge +

   <u>(3rd Year Estimated Dk x Distribution Delivery Charge)</u>/LARR

   Where: LARR = 11.626%

   The LARR, defined as the Levelized Annual Revenue Requirement Factor, is the annual rate required to recover the present value of a project over the life of a project.

FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105

d) Cost of the extension shall include the gas main extension(s), valves, service line(s), cathodic protection equipment, 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.

e) Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer.

f) Contributions. In the event the extension is not cost justified, the customer(s) shall pay the Company the portion of the capital expenditures not cost justified. The extension will proceed if the customer:

   i) Pays in advance to the Company the excess amount not cost justified in cash, or

   ii) Agrees to pay a special monthly charge. If the customer discontinues service prior to the excess being paid in full, the balance will be due and payable upon discontinuance of service, or

   iii) Agrees to pay annually a specified minimum charge. If the customer discontinues service prior to the excess being paid in full, the balance will be due and payable upon discontinuance of service, or

   iv) Agrees to a combination of above methods, or

   v) Customer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction and acceptable by the Company. Such bond, issued by a bonding company authorized to do business in the state or letter of credit 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.

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

vii) If within the five year period from the extension(s) in service date, the number of active customers and related volumes exceeds the projections used to determine MAI, the Company shall re-compute the contribution requirement by recalculating the MAI.

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

g) Refunds. Contributions for gas main extensions are refundable, without interest, for a period up to five (5) years from the date of completion of the main extension as additional customers are connected to the particular main extension for which the advance was made.

i) The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. Customers who have posted a bond or letter of credit will be notified of any reduction in surety or guarantee requirements.

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

iii) 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.

iv) No refund shall be made by Company after the five-year refund period and in no event shall the refund exceed the amount of the contribution.

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

i) Firm Gas Service Line Extensions:
The Company shall install gas service lines using the following general rules and regulations applicable to all firm gas service line extensions:

i) The term “service line” refers to facilities that are constructed from a main to the final terminus at a building or structure.

ii) The Company shall furnish, own, and maintain all material and equipment to the outlet side of the meter on the customer’s premise(s).

iii) The Company will extend a service line to serve customer(s) where natural gas is the primary fuel used for space heating without charge up to, but not to exceed, 65 feet. The length of the service line shall be determined by measurement from the customer’s property line to the stop valve on the service riser.

iv) If the additional service line required is beyond 65 feet or natural gas is not the primary fuel used for space heating, the Company may require cost participation if the estimated capital expenditure is not cost justified. The service line extension will be considered cost justified if the calculated MAI equals or exceeds the estimated capital expenditures using the MAI formula provided in ¶ c.ii.

v) Where cost participation is required, such extension is subject to execution of the Company’s standard agreement for extensions by the customer.

vi) Relocation of Existing Meters and Service Lines: When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and materials rates.

A minimum connection charge, per meter, covering the cost of the installation of the meter and regulator, the service connection, general inspection, and gas turn-on is payable at the time the application for service is submitted. The minimum connection charge is $25.00 per meter for customers with gas input loads up to 400,000 BTU/hour; and $50.00 per meter for customers with gas input loads above 400,000 BTU/hour.

INTERRUPTIBLE GAS MAIN AND SERVICE LINE EXTENSIONS POLICY Rate 106

The Company will install gas main and service line extensions using the following guidelines:

a) Contribution. Prior to construction, the customer shall contribute an amount equal to the total cost of construction including all gas main extensions, valves, service line(s), cathodic protection equipment, 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 applicable federal and state income taxes.

   i) The extension will proceed if the customer:

      (1) Pays in advance to the Company the total cost of construction, or

      (2) Customer may post a bond or irrevocable letter of credit in the amount of the required contribution prior to construction and acceptable by the Company. Such bond, issued by a bonding company authorized to do business in the state or letter of credit 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.

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

   iii) Remote data acquisition equipment costs shall be subject to the terms and conditions specified in the Company's Interruptible Gas Transportation Rates.

b) Refund. Contributions for gas main and service line extensions are refundable, without interest, for a period up to five (5) years from the date of completion of the main extension.

   i) 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, the Company shall refund the amount exceeding the revenue requirement on the following basis:

(1) Annually, beginning at the second (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.

(2) Customers who have posted a bond or letter of credit will be notified of any reduction in surety or guarantee requirements based on the above calculation.

(3) No refund shall be made by Company after the five-year refund period and in no event shall the refund exceed the amount of the contribution.

ii) If within the five-year period from the extension(s) in service date, additional customers (firm or interruptible) are connected to an interruptible customer's main extension, the Company shall (1) determine the pro rata cost share applicable to the other customer (2) reduce the original customer's contribution requirement by the pro rata cost attributed to the new customer and (3) calculate an MAI for a firm customer through the process described in Rate 105 ¶ c.ii or collect the full amount for an interruptible customer. The amount collected will be subject to the applicable refund provisions for the remainder of the refund period.

c) Relocation of Existing Meters and Service Lines: When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and material rates.

d) A minimum connection charge, per meter, covering the cost of the installation of the meter and regulator, the service connection, general inspection, and gas turn-on is payable at the time the application for service is submitted. The minimum connection charge is $100.00 for interruptible customers.

TABLE OF CONTENTS

COMMUNITIES SERVED

NATURAL GAS SERVICE

Dakota Heartland Region

Apple Valley	Eldridge	Max	Steele
Barlow	Fort Totten	Medina	Surrey
Bismarck*	Garrison	Milnor	Tappen
Burlington	Glen Ullin	Minot	Turtle Lake
Carrington	Grafton	New Rockford	Underwood
Cavalier	Gwinner	New Salem	Valley City
Cleveland	Jamestown	Park River	Walhalla
Dawson	Langdon	Riverdale	Washburn
Des Lacs	Lincoln	Ruthville	Wahpeton
Devils Lake	Linton	Sandborn	Wilton
	Mandan	Sheyenne	Locations near Hankinson/Fairmont

Badlands Region

Alexander	Gladstone	Palermo	Stanley
Arnegard	Golva	Ray	Taylor
Beach	Hebron	Regent	Tioga
Belfield	Killdeer	Rhame	Trenton
Berthold	Lefor	Richardton	Watford City
Bowman	Lignite	Ross	Wheelock
Dickinson*	Marmarth	Sentinel Butte	White Earth
East Fairview	Mott	Springbrook	Williston
Epping	New England	South Heart	

PROPANE SERVICE

Badlands Region

Hettinger

*Designates Region Office

Montana-Dakota Utilities Co.

400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 8
Original Sheet No. 3

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	Rates 88 & 99 Cost of Gas	Total Rate/ Dk
Residential Rate 60	4	$0.8919 per day	$0.000		
Air Force Rate 64	7				
Minot Air Force Base		$2,000.00 per month			
PAR Site		$175.00 per month			
Firm Service			$0.428		
Interruptible Service - PAR			$0.242		
Interruptible Service - MAFB			$0.242		
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.75 per day	$1.116		
Meters rated > 500 cubic feet		$2.13 per day	$0.887		
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$450.00 per month	$0.556		
Optional Seasonal Gas Rate 72	15				
Meters rated < 500 cubic feet		$0.75 per day	$1.116		
Meters rated > 500 cubic feet		$2.13 per day	$0.887		
Contracted Demand					
Service Rate 74	17		(Demand		
Meters rated < 500 cubic feet		$0.75 per day	Charge)	(Capacity Charge)	
Meters rated > 500 cubic feet		$2.13 per day	$8.000	(COG/Dk)	
Transportation Service	24				
Small Interruptible Rate 81		$450.00 per month			
Maximum			$0.556		
Minimum			$0.102		
Large Interruptible Rate 82		$1,600.00 per month			
Maximum			$0.239		
Minimum			$0.061		
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$1,600.00 per month	$0.239		
Residential Propane Rate 90	32	$0.8919 per day	$0.000		
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		$0.75 per day	$1.116		
Meters rated > 500 cubic feet		$2.13 per day	$0.887		

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Issued By: Travis R. Jacobson
Director - Regulatory Affairs **Case No.:** PU-20-

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

State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Rate Schedule - Phase I	Sheet No.	Basic Service Charge	Distribution Delivery Charge	Rate 89 Cost of Gas	Total Rate/ Dk
Residential Wahepton Rate 63	6	$0.250 per day	$1.028		
Firm General Wahpeton Rate 73	16				
Meters rated < 500 cubic feet		$0.250 per day	$1.028		
Meters rated > 500 cubic feet		$0.250 per day	$1.028		
Small Interruptible Gas Wahpeton			(Maximum)		(Maximum)
Rate 76	19	$180.00 per month	$0.670		
Transportation Service Wahpeton	26				
Small Interruptible Rate 83		$180.00 per month			
Maximum			$0.670		
Minimum			$0.130		
Large Interruptible Rate 84		$180.00 per month			
Maximum			$0.670		
Minimum			$0.130		
Large Interruptible Gas Wahpeton			(Maximum)		(Maximum)
Rate 86	28	$180.00 per month	$0.670		

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State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Miscellaneous Charges	Amount
Late Payment	1% per month
Returned Check	$15.00 per check
Manual Meter Reading Change	$26.05 per month
Reconnection charge after termination for nonpayment -During normal business hours -After normal business hours	 See Rate 100 paragraph 22 Current service labor rate per hour
Reconnection charge after termination for causes defined in Rate 100 paragraph 22 -During normal business hours -After normal business hours	 $30.00 Current service labor rate per hour
Reconnection charge applicable to seasonal or temporary customers -During normal business hours -After normal business hours	 Minimum- $30.00 (See rate 100 § V 21) Minimum- Current service labor rate per hour
Reconnection charge applicable to transportation customers when remote data acquisition equipment must be reinstalled	$160.00

RESIDENTIAL GAS SERVICE Rate 60

Availability:

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

Rate:

Basic Service Charge:	$0.8919 per day
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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

RESIDENTIAL GAS SERVICE – WAHPETON Rate 63

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule to Montana-Dakota Utilities Co.'s Residential Gas Service – Wahpeton Rate 63. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule and is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Firm Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton for all domestic uses. See Rate 100, §V.3, for definition on class of service.

Rate:

Phase I:

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$1.028 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Phase II:

Basic Service Charge:	$0.333 per day
Distribution Delivery Charge:	$0.649 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AIR FORCE Rate 64

Availability:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

Rate:

Basic Service Charge:	
Minot Air Force Base	$2,000.00 per month
Perimeter Acquisition Radar (PAR) Site	$175.00 per month
Distribution Delivery Charge:	
Firm Service	$0.428 per dk
Interruptible Service	$0.242 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If the 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 Service distribution delivery charge and cost of gas rates 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 $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.

2. CONTRACT – Terms of service other than the rate shall be specified in contracts between Minot Air Force Base, and PAR and the Company.

3. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AIR FORCE Distribution System Rate 65

Availability:

Operation and maintenance of the Minot Air Force Base distribution system near Minot, North Dakota.

Rate:

Distribution System Operation and Maintenance Fee	$35,500.00 per month (months 1-36) $38,000.00 per month (month 37 forward)
Amortization of Purchase Price	$(3,053.00) per month

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.13, or any amendments or alterations thereto.

General Terms and Conditions:

1. Terms of service including transition period fees shall be specified by contract between Minot Air Force Base and the Company.

2. The amortization on purchase price amount shall be a credit to the Minot Air Force Bill each month.

3. The foregoing schedule is subject to Rates 100 through 124 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.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served, except for Wahpeton, for all purposes except for resale. See Rate 100, §3, for definition on class of service.

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.75 per day
Distribution Delivery Charge:	$1.116 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$2.13 per day
Distribution Delivery Charge:	$0.887 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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:

The foregoing schedule is subject to Rates 100 through 124 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 Wahpeton, 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 100,000 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 interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$450.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$0.556 per dk	$0.103 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the Cost of Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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 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.11.

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 charges applicable under Firm General Gas Service Rate 70 (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 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.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

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

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.75 per day
Distribution Delivery Charge:	$1.116 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$2.13 per day
Distribution Delivery Charge:	$0.887 per dk

Cost of Gas:

Winter- Service rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Service rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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. The customer agrees to contract for service under the Optional Seasonal General Gas Service Rate 72 for a minimum of one year.

2. The foregoing schedule is subject to Rates 100 through 124 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.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

FIRM GENERAL GAS SERVICE - WAHPETON Rate 73

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule to Montana-Dakota Utilities Co.'s Firm General Gas Service – Wahpeton Rate 73. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule and is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Firm Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Phase I:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$1.028 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$1.028 per dk

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

Phase II:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.632 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$1.000 per day
Distribution Delivery Charge:	$0.507 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Availability:

In all communities served, except for Wahpeton, applicable to non-residential customers with standby natural gas generators and, available on an optional basis to, customers qualifying for service under the interruptible service tariffs that have requested, and received approval from the Company, for gas service under this rate.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.75 per day
For customers with meters rated over 500 cubic feet per hour	$2.13 per day
Distribution Demand Charge:	$8.00 per dk per month of billing demand
Capacity Charge per Monthly Demand dk:	Determined Monthly – See Rate Summary Sheet for Current Rate
Cost of Gas – Commodity per dk:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge, Distribution Demand Charge, and Capacity 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

Cost of Gas:

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

Metering Requirements:

1. Service provided for under tariff must be separately metered from customer's other gas services.

2. Remote data acquisition equipment (telemetering equipment) may be required by the Company for a single customer installation for daily measurement.

3. Customer may be required, upon consultation with the Company, to contribute towards any additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

4. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

General Terms and Conditions:

1. The customer agrees to contract for service under the Firm General Rate 74 for a minimum period of one year.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations therefore or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of North Dakota
Gas Rate Schedule

GWINNER PIPELINE CAPCACITY RESERVATION CHARGE Rate 75

Availability:

To customers provided natural gas service either directly or through another connection with the Company's pipeline interconnecting with the Alliance Pipeline near Milnor, North Dakota and running through Ransom and Sargent Counties to the Bobcat Company's facility located near Gwinner, North Dakota (Gwinner Pipeline).

Applicability:

Customers requesting natural gas service where service must be provided off the Gwinner Pipeline shall contract for capacity required to serve their annual requirements. The Reservation Charge shall be in addition to all other charges applicable under the otherwise applicable rate schedule 60, 70, 71, 72, 74, 81, 82, or 85.

Capacity Reservation Charge:

Residential Customers provided Service Under Rate 60	$0.8712 per day
All other Customers	$26.50 per maximum daily quantity reservation

Minimum Bill:

Capacity Reservation 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract except for residential customers that will be assessed the daily charge above. All other customers will specify a contract quantity based on the maximum daily quantity required. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

GWINNER PIPELINE CAPCACITY RESERVATION CHARGE Rate 75

General Terms and Conditions:

1. The customer agrees to contract for service under the Gwinner Pipeline Capacity Reservation Charge Rate 75 for a minimum period of one year.

2. Service under any other rate schedule is not available to customers served through the Gwinner Pipeline without a reservation for capacity on the Gwinner Pipeline.

3. Any main or service line extension necessary to provide service to the Customer shall be subject to the Firm Gas Service Extension Policy Rate 120 or Interruptible Service Extension Policy Rate 119.

4. The foregoing schedule is subject to the requirements set forth under the otherwise applicable rate schedule for natural gas service and Rates 100 through 124, including 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 – WAHPETON Rate 76

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule to Montana-Dakota Utilities Co.'s Small Interruptible General Gas Service – Wahpeton Rate 76. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule and is available to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Interruptible Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton 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 100,000 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 73. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Phase I:

Basic Service Charge:	$180.00 per month
Distribution Delivery Charge:	
Maximum	$0.670 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Phase II:

Basic Service Charge:	$250.00 per month
Distribution Delivery Charge:	
Maximum	$0.608 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the Cost of Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

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 Wahpeton firm 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.11.

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 charges applicable under Firm General Gas Service Rate 73, (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 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 for transportation of natural gas to customer's premise (metered at a single delivery point) through Company's distribution facilities, with the exception of Wahpeton and the surrounding areas. 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 100,000 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 100,000 dk annually metered at a single delivery point, 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:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71 or Rate 85, the Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived.

Basic Service Charge:	
Rate 81	$450.00 per month
Rate 82	$1,600.00 per month

	Rate 81	Rate 82
Maximum Rate per dk	$0.556	$0.239
Minimum Rate per dk	$0.102	$0.061

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. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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.11.

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 customer's behalf, shall be billed at the charges applicable under Firm General Gas Service Rate 70 (excluding Basic Service Charge), 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.

6. CUSTOMER USE OF NON-DELIVERED VOLUMES - 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 9.b. Gas volumes supplied by Company will be charged at charges applicable under Firm General Gas Service Rate 70 (excluding Basic Service Charge). The Company is under no obligation to notify customer of non-delivered volumes.

7. REPLACEMENT OR SUPPLEMENTAL SALES SERVICE - 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.

8. 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 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.

   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.21.

9. DAILY IMBALANCE:
   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.

b. In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.

c. 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. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Averages Prices" published by Gas Daily for CIG Rockies and Northern Ventura during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

11. METERING REQUIREMENTS:

a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards an additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

12. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper or agent shall advise the Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC timelines, of the dk requirements customer has requested to be delivered at each delivery point 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.

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

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.13, or any amendments 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. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Availability:

For the community of Wahpeton this service is applicable 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:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Interruptible Transportation Service - Rate 80 rate schedule to Montana-Dakota Utilities Co.'s Transportation Service – Wahpeton Rates 83 and 84. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Interruptible Transportation Service - Rate 80 rate schedule and is available to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Interruptible Transportation Service".

Phase II Availability *(effective start date of Phase II)*:
Small Interruptible General Gas Transportation Service - Wahpeton Rate 83:
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 100,000 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 - Wahpeton Rate 76. 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 – Wahpeton Rate 73.

Large Interruptible General Gas Transportation Service - Wahpeton Rate 84:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually metered at a single delivery point, 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 - Wahpeton Rate 86. 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 – Wahpeton Rate 73.

Rate:

Under Rate 83 or 84, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 76 or Rate 86, the Basic Service Charge applicable under Rate 83 or Rate 84 shall be waived.

Phase I:

Basic Service Charge:		
Rate 83	$180.00 per month	
Rate 84	$180.00 per month	
	Rate 83	Rate 84
Maximum Rate per dk	$0.670	$0.670
Minimum Rate per dk	$0.130	$0.130

Phase II:

Basic Service Charge:		
Rate 83	$250.00 per month	
Rate 84	$500.00 per month	
	Rate 83	Rate 84
Maximum Rate per dk	$0.608	$0.656
Minimum Rate per dk	$0.130	$0.130

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. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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 73. 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.11.

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 customer's behalf, shall be billed at the charges applicable under Firm General Gas Service - Wahpeton Rate 73, (excluding Basic Service Charge), 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.

6. CUSTOMER USE OF NON-DELIVERED VOLUMES - 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 9.b. Gas volumes supplied by Company will be charged at charges applicable under Firm General Gas Service - Wahpeton Rate 73. The Company is under no obligation to notify customer of non-delivered volumes.

7. REPLACEMENT OR SUPPLEMENTAL SALES SERVICE - 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.

8. 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 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.

   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.21.

9. DAILY IMBALANCE:
   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.

   b. In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.

   c. 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. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

    a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Averages Prices" published by Gas Daily for Emerson, Manitoba during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

11. METERING REQUIREMENTS:
    a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards an additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made

c. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

12. DAILY NOMINATION REQUIREMENTS:

a. Customer or customer's shipper or agent shall advise the Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC timelines, of the dk requirements customer has requested to be delivered at each delivery point 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.

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

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.13, or any amendments 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. The foregoing schedule is subject to Rates 100 through 124 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 for Wahpeton, for all interruptible general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually as metered at a single delivery point. 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.

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

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge:	$1,600.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$0.239 per dk	$0.061 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

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 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.11.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the charges applicable under Firm General Gas Service Rate 70 (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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 90 days prior to the end of the initial term. Absent execution of 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company, prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 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 - WAHPETON Rate 86

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule to Montana-Dakota Utilities Co.'s Large Interruptible General Gas Service – Wahpeton Rate 86. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule and is available to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Interruptible Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton for all interruptible general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually as metered at a single delivery point.

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 73. 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.

Rate:

Phase I:

Basic Service Charge:	$180.00 per month
Distribution Delivery Charge:	
Maximum	$0.670 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Phase II:

Basic Service Charge:	$500.00 per month
Distribution Delivery Charge:	
Maximum	$0.656 per dk
Minimum	$0.130 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

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 Wahpeton firm 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.11.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain 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 73, (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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 90 days prior to the end of the initial term. Absent execution of 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company, prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such

enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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 billing period from November 1 through May 1. Service provided under the Company's Firm General Service Rates 70 and 92 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 Firm General Service Rates 70 and 92 beginning with the first billing cycle starting November 1 through the billing cycle ending May 1. The DDSM adjustment will be applied on a real-time basis as a surcharge or credit on all rate schedules to which the DDSM is applicable to the customers' bills issued each month during the weather adjustment period of November 1 through May 1.

DDSM Adjustment Calculation:

The DDSM Adjustment shall be determined for each customer taking service under Firm General Services Rate 70 or 92. 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. The resulting product shall be multiplied by the applicable Distribution Delivery Charge rate per dk.

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

Where:

$DDSM_i$	=	Distribution Delivery Stabilization Adjustment
i	=	Customer served under Rate Schedules 70 or 92
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

Definitions:

Heating Degree Days	-	The deviation between the average daily temperatures and 60 degrees Fahrenheit.
Normal Degree Days	-	The heating degree days based on the 30-year average actual degree days.
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. Firm General Service Rate Code 700 = 0.05012 Firm General Service Rate Code 701 = 0.90499 Firm General Service Rate Code 920 = 0.04802 Firm General Service Rate Code 921 = 1.79780
Actual Degree Days	-	The actual degree days reported by the National Weather Service Stations for applicable service areas in North Dakota.

1. **Applicability:**
   This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of natural gas supply, (b) amortization of the Unrecovered Purchased Gas Cost Account and (c) grain drying margin sharing.

2. **Effective Date and Limitation on Adjustments:**
   (a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.

   (b) Montana-Dakota shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least twenty-five (25) cents per dk. The adjustment to be effective October 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
   (a) The monthly COG shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing. 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. 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.

   (b) The COG 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 COG 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 adjusted to reflect losses.

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

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

(3) Demand costs for firm general contracted demand customers shall be stated on the incremental MDDQ basis.

(4) 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.

(5) 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.

(6) 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 COG shall be applied to each of Montana-Dakota's rate schedules recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

4. Surcharge Adjustment:

(a) All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on October 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 Purchased Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Account (Account 191), as calculated in accordance with Subsection 5(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in the COG by reason of the twenty-five 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.

(4) Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

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

(b) (1) The amount to be included in Account 191 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 supplier's 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 COG.

(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 Account 191 for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in Account 191 at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. 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 Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 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. 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 Account 191 specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Account 191 specified in Subsection 5(a)(4).

6. Grain Drying Margin Sharing Mechanism:
At the time of each surcharge adjustment, pursuant to Paragraph 4, the Company will compute a credit to Rates 60, 70, 72, and 74 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service rates as established in Case No. PU-13-803, including prior period over or under collected balances.

7. Time and Manner of Filing:

(a) Montana-Dakota shall file to change the COG at least 20 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised COG sheets identifying the amounts of the adjustments and the resulting currently effective COG rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant pipeline tariff sheets supporting costs claimed.

COST OF GAS – NATURAL GAS WAHPETON Rate 89

1. **Applicability:**
   This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under the Company's Wahpeton rate schedules in order to reflect: (a) changes in the Company's average cost of natural gas supply and (b) amortization of the Gas Cost Reconciliation account.

2. **Effective Date and Limitation on Adjustments:**
   (a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.

   (b) Montana-Dakota shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least $0.25 per dk. The adjustment to be effective June 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
   (a) The monthly COG shall reflect changes in Wahpeton's cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing.

   (b) Firm Demand - The average cost of demand for Wahpeton's firm gas sales shall be computed on the basis of current pipeline rates and contract demand divided by twelve-month weather normalized sales volumes applicable for the gas supply system serving Wahpeton and Minnesota customers.

   (c) Gas Commodity - The average weighted commodity cost, including transportation and other costs associated with the acquisition of gas, from all suppliers for the month the COG will be in effect.

   (d) Prepaid Commodity and Storage Balances – The return on prepaid commodity and storage balances shall be computed on an annual basis and shall be apportioned 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.

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

COST OF GAS – NATURAL GAS WAHPETON Rate 89

4. Gas Cost Reconciliation (GCR)

(a) For each twelve-month period ending April 30, a Gas Cost Reconciliation (GCR) will be calculated for each class set forth above. The GCR will be added to each customer class' cost of gas supply for the twelve-month period effective June 1 of each year. This adjustment shall include:

1. The balance in the (over) under recovered gas cost account as of April 30.
2. The difference between actual and recovered gas costs for each customer class for the twelve months ending April 30. The amount may be an under recovery or (over) recovery.
3. Demand costs recovered from the interruptible sales customers will be credited to the firm service customers.
4. Any refunds from suppliers of gas or pipeline services.
5. Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

(b) The resulting balance is divided by the projected dk sales for the next twelve months. The GCR adjustment shall be applied to the customers' monthly billings commencing on June 1 and remain in effective for a twelve (12) month period.

RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.8919 per day
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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.75 per day
Distribution Delivery Charge:	$1.116 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$2.13 per day
Distribution Delivery Charge:	$0.887 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of propane as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane 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:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

COST OF GAS – PROPANE Rate 99

1. **Availability:**
   This rate schedule constitutes a Cost of Gas (COG) provision and specifies the procedure to be utilized to adjust the rates for propane gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of propane supply, (b) amortization of the Unrecovered Purchased Cost of Gas Account and (c) grain drying margin sharing.

2. **Effective Date and Limitation on Adjustments:**
   (a) The effective dates of the COG shall be service rendered on and after the first day of each month, unless the Commission shall otherwise order.

   (b) Montana-Dakota shall file to reflect changes in its average cost of propane supply only when the amount of such change in COG is at least twenty-five (25) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
   (a) The monthly COG shall reflect changes in Montana-Dakota's cost of propane supply as compared to the cost of propane supply approved in its most recent COG filing. The cost of propane supply shall include, but not be limited to, all commodity and transportation charges incurred by Montana-Dakota for such propane supply.

   (b) The propane commodity cost shall reflect all commodity related propane costs estimated to be incurred for the month the COG will be in effect and estimated dk purchases.

   The unit cost per dk for the month shall be the commodity costs divided by estimated dk purchases for the month.

4. **Surcharge Adjustment:**
   All propane sales schedules shall be subject to a Surcharge Adjustment to be effective on May 1 each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Cost of Gas 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 Purchased Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Account (Account 191), as calculated in accordance with Subsection 5(b) are:

(1) Charges for propane supply which Montana-Dakota is unable to reflect in the COG by reason of the twenty-five cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for propane supplies that were paid during any period after the effective date of the most recent approved rates, but not yet included in propane sales rates.

(3) Carrying charges or credits.

(b)

(1) The amount to be included in Account 191 in order to reflect the items specified in Subsections 5(a)(1) and (2) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's propane supply.

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

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each propane rate schedule. The resulting amounts shall be reflected in an Account 191 for each rate schedule.

Montana-Dakota will calculate carrying charges on the amounts in Account 191 as follows:

Each month, Account 191 shall be debited (on a debit balance) or credited (on a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

(i) The balance on 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 three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The carrying charges shall be accrued in a supplementary Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 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. 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 Account 191 specified in Subsections 5(a)(1) and (2) and the amounts in the supplementary Account 191 specified in Subsection 5(b)(2)(ii).

6. Grain Drying Margin Sharing Mechanism:

At the time of each surcharge adjustment, pursuant to Paragraph 4 of Rate 88, the Company will compute a credit to Rates 90 and 92 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service rates as established in Case No. PU-13-803, including prior period over or under collected balances.

7. Time and Manner of Filing:

(a) Montana-Dakota shall file each COG at least 10 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised COG sheets identifying the amounts of the adjustments and the resulting currently effective COG rates.

COST OF GAS – PROPANE Rate 99

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant material supporting costs claimed.

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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 Service Commission of North 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 Service Commission of the State of North 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 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.

EXCESS FLOW VALVE – Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.

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

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, 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 OBLIGATION:**

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 person 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 required to make a deposit as required by the Company.

2. SERVICE AVAILABILITY – Gas will normally be delivered at standard pressures of four to six ounces, dependent on the service territory where the gas service is being delivered. Delivery of gas service at pressures greater than the standard operating pressure may be available and will require a consultation with the Company to determine availability.

3. 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 ensure that such

equipment will conform to the Company's ability to adequately serve such installations with gas.

4. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises Monday through Friday, 8:00 a.m. to 5:00 p.m., unless an emergency requires access outside of these hours, for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

5. 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.

6. 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.

7. 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 or permits.

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

9. TERMINATION OF 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.

10. 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.

11. QUALITY OF GAS – The gas tendered to the Company shall conform to the applicable quality specifications of the transporting Pipeline's tariff.

IV. **LIABILITY**

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

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. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on the customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues and appliances on the customer's side of the point of delivery.

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, 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 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 authorization 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 with separate cooking facilities. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes with separate meters and sorority and fraternity houses. In addition, auxiliary buildings on the same premise as the living quarters when used for residential purposes may be served on the residential rate. This is not an all-inclusive list.

   (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 salons, 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 Homes 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.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with the following criteria:
   (a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   (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 be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. 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.

   A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.

   Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for twelve months, provided prompt payment record 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) Interruptible sales and transportation service customers agree to provide the cost of the installation of remote data acquisition equipment; as required, to the Company before service is implemented as provided for in the applicable rate schedule.

(c) 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, provided the equipment shall not interfere with such delivery or with the Company's meter.

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 (60ºF). 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, supercompressibility calculation. For handbilled accounts, application of supercompressibility factors will be waived on monthly-billed volumes of 250 dk or less.

Local sales base pressure is defined as four to six ounces (depending on service area) per square inch gauge pressure plus local average atmospheric pressure.

10. BILLING ADJUSTMENTS –
    (a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as Residential Service Rates 60, 63 or 90, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as non-residential (gas service provided under all rate schedules other than Rates 60, 63 or 90), the Company may adjustment back and rebill the bills in error for a period not to exceed six years.

    (d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and

refund the customer the amount of the overbilled for a period not to exceed six years from the date of payment.

11. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from Highest to Lowest:
    (a) Priority 1 – Firm sales services.
    (b) Priority 2 – Small interruptible sales at the maximum rate on a pro rata basis.
    (c) Priority 3 – Small interruptible sales at less than the maximum rate from the highest rate to the lowest rate on the pro rata basis where equal rates are applicable among customers.
    (d) Priority 4 – Large interruptible sales at the maximum rate on a pro rata basis.
    (e) Priority 5 – Small interruptible transportation services from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    (f) Priority 6 – Large interruptible transportation services from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    (g) Priority 7 – Gas scheduled to clear imbalances.

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

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

12. EXCESS FLOW VALVE – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.

13. 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 percent per month will be applied to any past due balance, 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.

14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for any check for any reason not honored by customer's bank.

15. MANUAL METER READING CHARGE– A monthly Manual Meter Reading Charge of $26.05 per month will be assessed customer(s) who have requested, and received Company approval, to have their meter read manually each month in lieu of an AMR-equipped meter read. Customer(s) agree to contract for the manual reading of the meter for a minimum period of one year.

16. 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 customer's 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.

17. 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 fumes.

(3) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

(4) Maintenance or repair of Company-owned facilities on the customer's premises.

(5) Pilot relights necessary due to an interruption in gas service deemed to be the Company's responsibility.

(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) High bills or inadequate service complaints.

(3) Location of underground Company facilities for contractors, builders, plumbers, etc.

18. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.

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.

To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

19. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service disconnected shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, or telephone call to the Company's Customer Service Center. Saturdays, Sundays and legal holidays are not considered business days.

20. 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.

21. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER – A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee as follows:

    Residential - The Basic Service Charge applicable during the period service was not being used and a charge of $30.00. The minimum will be based on standard overtime rates for reconnecting service after normal business hours.

    Non-Residential – The Basic Service Charge applicable during the period while service was not being used. However, the reconnection charge applicable to seasonal business concerns such as irrigation, swimming facilities, grain drying and asphalt processing shall be the Basic Service Charge applicable during the period while service was not being used less the Distribution Delivery Charge revenue collected during the period in-service for usage above the annual authorized usage by rate class (Small Firm General Rate 70 = 174 dk; Large Firm General Rate 70 = 1,220 dk; Small Firm General Rate 73 = 231 dk; Large Firm General Rate 73 = 525 dk; Small Firm General Propane Rate 92 = 170 dk; Large Firm General Propane Rate 92 = 1,898 dk; and Small Interruptible = 5,918 dk). A reconnection fee of $30.00 will also apply to reconnections. The minimum will be based on standard overtime rates for reconnecting service occurring after normal business hours.

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

22. 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. For calls received after 12:00 p.m. on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

23. 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.

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

    (a) Examples of unauthorized use of service includes but is not limited to, tampering or unauthorized reconnection by the following methods:
        (1) Bypass piping around meter.
        (2) Bypass piping installed in place of meter.
        (3) Meter reversed.
        (4) Meter index disengaged or removed.
        (5) Service or equipment tampered with or piping connected ahead of meter.
        (6) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
        (7) Gas being used after service has been discontinued by the Company. 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) In the event that there has been unauthorized use of service, customer shall be charged for:
        (1) Time, material and transportation costs used in investigation.
        (2) Estimated charge for non-metered gas.
        (3) On-premise time to correct situation.
        (4) Any damage to Company property.
        (5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.

(c) Reconnection of Service:
Gas service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service, and paid any service charges which are due, including:
(1) All delinquent bills, if any.
(2) The amount of any Company revenue loss attributable to said tampering.
(3) Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in number 20.b above.
(4) Reconnection fee applicable.
(5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

25. BILL DISCOUNT FOR QUALIFYING EMPLOYEES – A bill discount may be available for residential use only in a single family unit served by Montana-Dakota to qualifying retirees of MDU Resources and its subsidiaries. The bill shall be computed at applicable rate and the amount reduced by 33 1/3 percent.

26. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:

Rate 119 – Interruptible Gas Service Extension Policy
Rate 120 – Firm Gas Service Extension Policy
Rate 124 –Replacement, Relocation and Repair of Gas Service Lines

GAS METER TESTING PROGRAM Rate 105

Applicability:

This rate schedule specifies the protocol to be followed for the testing of gas meters in compliance with Sections 69-09-01-14 and 69-09-01-16 of the North Dakota Century Code.

Testing Process for New Meters

1. Meter supplier(s) shall provide test data for all new meters.

2. A sampling of 5% of new meter lots received will be tested at full load and light load. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or the shipment shall be returned to the manufacturer.

Testing Process for Meters in Service

1. This meter test schedule shall not apply to meters larger than 650 cubic feet per hour (cfh). Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.

2. All active meters, 650 cfh and smaller, will be combined into a single random test program. The population of meters shall come from the states of North Dakota, Montana, South Dakota, and Wyoming.

3. At the time the random selection is made, meters more than ten years old and active meters that have not been tested in the last ten years will be placed into an installation class defined model installation date lot (lot) to be part of a random population for testing.

4. All active meters will be assigned to lots on the basis of installation date. Meters shall be divided into lots based on manufacturer, type, and last install date in five year groups. The minimum number of samples taken from each lot will be as specified by Military Standard 414, Sample Procedures and Tables for Inspection by Variables for Percent Defective, inspection level IV with specification limits of + 2.0%.

5. The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.

6. Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable quality level of 15%. The following actions will be taken based on the test results:

    a. A meter for which the sample is satisfactory will remain in service.

    b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.

    c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% of the sample registers over 102%

        i. If evaluation determines the group is homogeneous, then the entire group will be removed.

        ii. If group is not homogeneous and a subset of the group is found defective, that subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.

Reporting

Montana-Dakota shall file reports of its meter test results by December 1 for the meter testing conducted between June 30 of the previous year and July 1.

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 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, service line(s), regulators, meters, 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. Remote data acquisition equipment cost's shall be subject to the terms and conditions specified in the applicable interruptible service rate schedule.

   (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, ora 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, or letter of credit, 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 shall pay the Company for such contribution requirement.

   (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 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's, 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 or letter of credit, will be notified of any reduction in surety 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 (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.

    (d) The Company and customer may enter into a contract providing for a refund mechanism based on customer meeting identified minimums on the basis of specific extension characteristics.

FIRM GAS SERVICE EXTENSION POLICY Rate 120

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm sales 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 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 or Demand Charge)/LARR

   where: LARR = Levelized Annual Revenue Requirement Factor of 12.757%

4. Cost of the extension shall include the gas main extension(s), valves, service line(s), any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs up to, and including, the riser.

   The service line is that portion of the gas service extending from the gas 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 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. A minimum annual charge set forth in an agreement between customer and Company, or
      iv. Customer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state,

or letter of credit, 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 exits in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement.

(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 volumes 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. Customers who have posted a bond or letter of credit, will be notified of any reduction in surety 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 a project consisting of 10 or more customers requesting service when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. If the Company and customers mutually agree that the project will be funded through a Surcharge, the project will be designated an expansion area and the Surcharge will be applicable to all connections within the expansion area. 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 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 in a five-year period.

(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 a mobile home court, in which a developer is installing roads, utilizes, 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 3.

(b) The contribution shall be made by:

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

ii. Developer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state or, letter of credit 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.

(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. Developers who have posted a bond, or a letter of credit will be notified of any reduction in surety 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.

REPLACEMENT, RELOCATION
AND REPAIR OF GAS SERVICE LINES Rate 124

1. 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.), the customer shall be charged for on the basis of direct costs incurred by the Company.

2. 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 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.

3. 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 the Firm Gas Service Extension Policy - Rate 120.

Tariffs Reflecting Proposed Changes

TABLE OF CONTENTS

COMMUNITIES SERVED

NATURAL GAS SERVICE

Dakota Heartland Region

Apple Valley	Eldridge	Max	Steele
Barlow	Fort Totten	Medina	Surrey
Bismarck*	Garrison	Milnor	Tappen
Burlington	Glen Ullin	Minot	Turtle Lake
Carrington	Grafton	New Rockford	Underwood
Cavalier	Gwinner	New Salem	Valley City
Cleveland	Jamestown	Park River	Walhalla
Dawson	Langdon	Riverdale	Washburn
Des Lacs	Lincoln	Ruthville	Wahpeton
Devils Lake	Linton	Sandborn	Wilton
	Mandan	Sheyenne	Locations near Hankinson/Fairmont

Badlands Region

Alexander	Gladstone	Palermo	Stanley
Arnegard	Golva	Ray	Taylor
Beach	Hebron	Regent	Tioga
Belfield	Killdeer	Rhame	Trenton
Berthold	Lefor	Richardton	Watford City
Bowman	Lignite	Ross	Wheelock
Dickinson*	Marmarth	Sentinel Butte	White Earth
East Fairview	Mott	Springbrook	Williston
Epping	New England	South Heart	

PROPANE SERVICE

Badlands Region

Hettinger

*Designates Region Office

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

State of North Dakota
Gas Rate Schedule

RESIDENTIAL GAS SERVICE Rate 60

Availability:

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

Rate:

Basic Service Charge:	$~~0.6860~~0.8919 per day
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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

RESIDENTIAL GAS SERVICE – WAHPETON Rate 63

Availability:

Phase I Availability *(effective dates for Phase I)*:

Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule to Montana-Dakota Utilities Co.'s Residential Gas Service – Wahpeton Rate 63. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule and is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Firm Gas Service".

Phase II Availability *(effective start date of Phase II)*:

For the community of Wahpeton for all domestic uses. See Rate 100, §V.3, for definition on class of service.

Rate:

Phase I:

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$1.028 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Phase II:

Basic Service Charge:	$0.333 per day
Distribution Delivery Charge:	$0.649 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AIR FORCE Rate 64

Availability:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

Rate:

Basic Service Charge:	
Minot Air Force Base	$2,000.00 per month
Perimeter Acquisition Radar (PAR) Site	$175.00 per month
Distribution Delivery Charge:	
Firm Service	$~~0.329~~0.428 per dk
Interruptible Service	$~~0.177~~0.242 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If the 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 Service distribution delivery charge and cost of gas rates 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 $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.

2. CONTRACT – Terms of service other than the rate shall be specified in contracts between Minot Air Force Base, and PAR and the Company.

3. The foregoing schedule is subject to Rates 100 through 124 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 North Dakota
Gas Rate Schedule

AIR FORCE Distribution System Rate 65

Availability:

Operation and maintenance of the Minot Air Force Base distribution system near Minot, North Dakota.

Rate:

Distribution System Operation and Maintenance Fee	\$35,500.00 per month (months 1-36) \$38,000.00 per month (month 37 forward)
Amortization of Purchase Price	\$(3,053.00) per month

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~~13, or any amendments or alterations thereto.

General Terms and Conditions:

1. Terms of service including transition period fees shall be specified by contract between Minot Air Force Base and the Company.

2. The amortization on purchase price amount shall be a credit to the Minot Air Force Bill each month.

3. The foregoing schedule is subject to Rates 100 through 124 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 North Dakota
Gas Rate Schedule

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities, except for Wahpeton, served for all purposes except for resale. See Rate 100, §3, for definition on class of service.

Rate:

~~Basic Service Charge:~~For customers with meters rated under 500 cubic feet per hour	
~~For customers with meters rated under 500 cubic feet per hour~~Basic Service Charge:	$0.~~70~~75 per day
Distribution Delivery Charge:	$1.116 per dk
For customers with meters rated over 500 cubic feet per hour	
Basic Service Charge:	$2.~~05~~13 per day
Distribution Delivery Charge:	$0.~~811~~887 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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:

The foregoing schedule is subject to Rates 100 through 124 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 North Dakota
Gas Rate Schedule

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Availability:

In all communities served, except for Wahpeton, 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 100,000 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 interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$~~190.00~~450.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$~~1.063~~0.556 per dk	$0.~~668~~102 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the Cost of Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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.11.

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 charges applicable under Firm General Gas Service Rate 70 (~~distribution delivery charge and cost of gas~~excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

~~Reserved for Future Use~~

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

State of North Dakota
Gas Rate Schedule

NDPSC Volume ~~7~~8
~~13th Revised~~ Original Sheet No. 15
~~Cancelling 12th Revised Sheet No. 15~~

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

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

Rate:

For customers with meters rated under 500 cubic feet per hour~~Basic Service Charge:~~	
Basic Service Charge:	$0.~~70~~75 per day
Distribution Delivery Charge:	$1.116 per dk
~~For customers with meters rated under 500 cubic feet per hour~~	
For customers with meters rated over 500 cubic feet per hour	
Basic Service Charge:	$2.~~05~~13 per day
Distribution Delivery Charge:	$0.~~811~~887 per dk
Cost of Gas:	
Winter- Service rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Service rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.13, or any amendments or alterations thereto.

Cost of Gas:

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

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

State of North Dakota
Gas Rate Schedule

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

General Terms and Conditions:

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

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: ~~October 5, 2018~~August 26, 2020
Effective Date: ~~Service rendered on and after December 1, 2018~~
Issued By: ~~Tamie A. Aberle~~Travis R. Jacobson
Director – Regulatory Affairs
Case No.: PU-~~17-295~~20-___

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

State of North Dakota
Gas Rate Schedule

FIRM GENERAL GAS SERVICE - WAHPETON Rate 73

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule to Montana-Dakota Utilities Co.'s Firm General Gas Service – Wahpeton Rate 73. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule and is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Firm Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Phase I:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$1.028 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$1.028 per dk

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

Phase II:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.632 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$1.000 per day
Distribution Delivery Charge:	$0.507 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

The foregoing schedule is subject to Rates 100 through 124 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 North Dakota
Gas Rate Schedule

NDPSC Volume ~~7~~8
Original Sheet No.~~16~~17

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Availability:

In all communities served, except for Wahpeton, applicable to non-residential customers with standby natural gas generators and, available on an optional basis to, customers qualifying for service under the interruptible service tariffs that have requested, and received approval from the Company, for gas service under this rate.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.~~70~~75 per day
For customers with meters rated over 500 cubic feet per hour	$2.~~05~~13 per day
Distribution Demand Charge:	$~~6.51~~8.00 per d~~D~~k per month of billing demand
Capacity Charge per Monthly Demand d~~D~~k:	Determined Monthly – See Rate Summary Sheet for Current Rate
Cost of Gas – Commodity per d~~D~~k:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge, Distribution Demand Charge, and Capacity 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

Date Filed:	~~October 5, 2018~~August 26, 2020	**Effective Date:**	~~Service rendered on and after December 1, 2018~~
Issued By:	~~Tamie A. Aberle~~Travis R. Jacobson Director - Regulatory Affairs	**Case No.:**	PU-~~17-295~~20-___

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Cost of Gas:

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

Metering Requirements:

1. Service provided for under tariff must be separately metered from customer's other gas services.

2. Remote data acquisition equipment (telemetering equipment) may be required by the Company for a single customer installation for daily measurement.

3. Customer may be required, upon consultation with the Company, to contribute towards any additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

4. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

General Terms and Conditions:

1. The customer agrees to contract for service under the Firm General Rate 74 for a minimum period of one year.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations therefore or additional rules and regulations promulgated by the Company under the laws of the state.

GWINNER PIPELINE CAPCACITY RESERVATION CHARGE Rate 75

Availability:

To customers provided natural gas service either directly or through another connection with the Company's pipeline interconnecting with the Alliance Pipeline near Milnor, North Dakota and running through Ransom and Sargent Counties to the Bobcat Company's facility located near Gwinner, North Dakota (Gwinner Pipeline).

Applicability:

Customers requesting natural gas service where service must be provided off the Gwinner Pipeline shall contract for capacity required to serve their annual requirements. The Reservation Charge shall be in addition to all other charges applicable under the otherwise applicable rate schedule 60, 70, 71, 72, 74, 81, 82, or 85.

Capacity Reservation Charge:

Residential Customers provided Service Under Rate 60	$0.8712 per day
All other Customers	$26.50 per maximum daily quantity reservation

Minimum Bill:

Capacity Reservation 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.1~~2~~3, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract except for residential customers that will be assessed the daily charge above. All other customers will specify a contract quantity based on the maximum daily quantity required. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

GWINNER PIPELINE CAPCACITY RESERVATION CHARGE Rate 75

General Terms and Conditions:

1. The customer agrees to contract for service under the Gwinner Pipeline Capacity Reservation Charge Rate 75 for a minimum period of one year.

2. Service under any other rate schedule is not available to customers served through the Gwinner Pipeline without a reservation for capacity on the Gwinner Pipeline.

3. Any main or service line extension necessary to provide service to the Customer shall be subject to the Firm Gas Service Extension Policy Rate 120 or Interruptible Service Extension Policy Rate 119.

4. The foregoing schedule is subject to the requirements set forth under the otherwise applicable rate schedule for natural gas service and Rates 100 through 124, including 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 – WAHPETON Rate 76

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule to Montana-Dakota Utilities Co.'s Small Interruptible General Gas Service – Wahpeton Rate 76. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule and is available to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Interruptible Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton 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 100,000 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 73. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Phase I:

Basic Service Charge:	$180.00 per month
Distribution Delivery Charge:	
Maximum	$0.670 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Phase II:

Basic Service Charge:	$250.00 per month
Distribution Delivery Charge:	
Maximum	$0.608 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the Cost of Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

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 Wahpeton firm 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.11.

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 charges applicable under Firm General Gas Service Rate 73, (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state

Availability:

This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through Company's distribution facilities, with the exception of Wahpeton and the surrounding areas. 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 100,000 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 100,000 dk annually metered at a single delivery point, 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:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71 or Rate 85, the Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived.

Basic Service Charge:	
Rate 81	$~~190.00~~450.00 per month
Rate 82	$~~1,500.00~~1,600.00 per month

	Rate 81	Rate 82
Maximum Rate per dk	$0.~~668~~556	$0.~~231~~239
Minimum Rate per dk	$0.102	$0.061

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. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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.11.

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 customer's behalf, shall be billed at the charges applicable under Firm General Gas Service Rate 70 (~~distribution delivery charge and cost of gas~~excluding Basic Service Charge), 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.

6. CUSTOMER USE OF NON-DELIVERED VOLUMES - 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 9.b. Gas volumes supplied by Company will be charged at charges applicable under Firm General Gas Service Rate 70 (~~distribution delivery charge and cost of gas~~excluding Basic Service Charge). The Company is under no obligation to notify customer of non-delivered volumes.

7. REPLACEMENT OR SUPPLEMENTAL SALES SERVICE - 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.

8. 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 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.

   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.~~20~~21.

9. DAILY IMBALANCE:
   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.

b. In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.

c. 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. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Averages Prices" published by Gas Daily for CIG Rockies and Northern Ventura during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

11. METERING REQUIREMENTS:

a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards an additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made

c. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

12. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper or agent shall advise the Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC timelines, of the dk requirements customer has requested to be delivered at each delivery point 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.

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

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.13, or any amendments 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. The foregoing schedule is subject to Rates 100 through 124 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~~

~~Reserved for Future Use~~

~~Reserved for Future Use~~

Availability:

For the community of Wahpeton this service is applicable 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:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Interruptible Transportation Service - Rate 80 rate schedule to Montana-Dakota Utilities Co.'s Transportation Service – Wahpeton Rates 83 and 84. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Interruptible Transportation Service - Rate 80 rate schedule and is available to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Interruptible Transportation Service".

Phase II Availability *(effective start date of Phase II)*:
Small Interruptible General Gas Transportation Service - Wahpeton Rate 83:
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 100,000 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 - Wahpeton Rate 76. 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 – Wahpeton Rate 73.

Large Interruptible General Gas Transportation Service - Wahpeton Rate 84:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually metered at a single delivery point, 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 - Wahpeton Rate 86. 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 – Wahpeton Rate 73.

Rate:

Under Rate 83 or 84, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 76 or Rate 86, the Basic Service Charge applicable under Rate 83 or Rate 84 shall be waived.

Phase I:

Basic Service Charge:

Rate 83	$180.00 per month
Rate 84	$180.00 per month

	Rate 83	Rate 84
Maximum Rate per dk	$0.670	$0.670
Minimum Rate per dk	$0.130	$0.130

Phase II:

Basic Service Charge:

Rate 83	$250.00 per month
Rate 84	$500.00 per month

	Rate 83	Rate 84
Maximum Rate per dk	$0.608	$0.656
Minimum Rate per dk	$0.130	$0.130

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. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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 73. 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.11.

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 customer's behalf, shall be billed at the charges applicable under Firm General Gas Service - Wahpeton Rate 73, (excluding Basic Service Charge), 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.

6. CUSTOMER USE OF NON-DELIVERED VOLUMES - 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 9.b. Gas volumes supplied by Company will be charged at charges applicable under Firm General Gas Service - Wahpeton Rate 73. The Company is under no obligation to notify customer of non-delivered volumes.

7. REPLACEMENT OR SUPPLEMENTAL SALES SERVICE - 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.

8. 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 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.

   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.21.

9. DAILY IMBALANCE:
   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.

   b. In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.

   c. 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. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

    a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Averages Prices" published by Gas Daily for Emerson, Manitoba during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

11. METERING REQUIREMENTS:

a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards an additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made

c. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

12. DAILY NOMINATION REQUIREMENTS:

a. Customer or customer's shipper or agent shall advise the Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC timelines, of the dk requirements customer has requested to be delivered at each delivery point 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.

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

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.13, or any amendments 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. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

State of North Dakota
Gas Rate Schedule

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served, except for Wahpeton, for all interruptible general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually as metered at a single delivery point. 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.

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

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge:	$~~1,500.00~~1,600.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$0.~~718~~239 per dk	$0.~~231~~061 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

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, 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.11.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the charges applicable under Firm General Gas Service Rate 70 (~~distribution delivery charge and cost of gas~~excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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 90 days prior to the end of the initial term. Absent execution of 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company, prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 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 North Dakota**~~
~~**Gas Rate Schedule**~~

~~Reserved for Future Use~~

~~**Date Filed:**~~	~~October 5, 2018~~	~~**Effective Date:**~~	~~Service rendered on and after December 1, 2018~~
~~**Issued By:**~~	~~Tamie A. Aberle~~ ~~Director – Regulatory Affairs~~	~~**Case No.:**~~	~~PU-17-295~~

LARGE INTERRUPTIBLE GENERAL GAS SERVICE - WAHPETON Rate 86

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule to Montana-Dakota Utilities Co.'s Large Interruptible General Gas Service – Wahpeton Rate 86. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule and is available to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Interruptible Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton for all interruptible general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually as metered at a single delivery point.

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 73. 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.

Rate:

Phase I:

Basic Service Charge:	$180.00 per month
Distribution Delivery Charge:	
Maximum	$0.670 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Phase II:

Basic Service Charge:	$500.00 per month
Distribution Delivery Charge:	
Maximum	$0.656 per dk
Minimum	$0.130 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

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 Wahpeton firm 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.11.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain 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 73, (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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 90 days prior to the end of the initial term. Absent execution of 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company, prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such

enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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 billing period from November 1 through May 1. Service provided under the Company's Firm General Service Rates 70 and 92 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 Firm General Service Rates 70 and 92 beginning with the first billing cycle starting November 1 through the billing cycle ending May 1. The DDSM adjustment will be applied on a real-time basis as a surcharge or credit on all rate schedules to which the DDSM is applicable to the customers' bills issued each month during the weather adjustment period of November 1 through May 1.

DDSM Adjustment Calculation:

The DDSM Adjustment shall be determined for each customer taking service under Firm General Services Rate 70 or 92. 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. The resulting product shall be multiplied by the applicable Distribution Delivery Charge rate per dk.

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

Where:

$DDSM_i$	=	Distribution Delivery Stabilization Adjustment
i	=	Customer served under Rate Schedules 70 or 92
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

DISTRIBUTION DELIVERY STABILIZATION MECHANISM Rate 87

Definitions:

Heating Degree Days	-	The deviation between the average daily temperatures and 60 degrees Fahrenheit.
Normal Degree Days	-	The heating degree days based on the 30-year average actual degree days.
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. Firm General Service Rate Code 700 = ~~0.03184~~0.05012 Firm General Service Rate Code 701 = ~~0.74281~~0.90499 Firm General Service Rate Code 920 = ~~0.01994~~0.04802 Firm General Service Rate Code 921 = ~~2.38427~~1.79780
Actual Degree Days	-	The actual degree days reported by the National Weather Service Stations for applicable service areas in North Dakota.

COST OF GAS – NATURAL GAS Rate 88

1. **Applicability:**
This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of natural gas supply, (b) amortization of the Unrecovered Purchased Gas Cost Account and (c) grain drying margin sharing.

2. **Effective Date and Limitation on Adjustments:**
(a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.

(b) Montana-Dakota shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least twenty-five (25) cents per dk. The adjustment to be effective October 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
(a) The monthly COG shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing. 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. 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.

(b) The COG 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 COG 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 adjusted to reflect losses.

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

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

(3) Demand costs for firm general contracted demand customers shall be stated on the incremental MDDQ basis.

(4) 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.

(5) 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.

(6) 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 COG shall be applied to each of Montana-Dakota's rate schedules recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

4. Surcharge Adjustment:

(a) All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on October 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 Purchased Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Account (Account 191), as calculated in accordance with Subsection 5(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in the COG by reason of the twenty-five 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.

(4) Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

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

(b) (1) The amount to be included in Account 191 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 supplier's 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 COG.

(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 Account 191 for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in Account 191 at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. 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 Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 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. 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 Account 191 specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Account 191 specified in Subsection 5(a)(4).

6. Grain Drying Margin Sharing Mechanism:
At the time of each surcharge adjustment, pursuant to Paragraph 4, the Company will compute a credit to Rates 60, 70, 72, and 74 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service rates as established in Case No. PU-13-803, including prior period over or under collected balances.

7. Time and Manner of Filing:

(a) Montana-Dakota shall file to change the COG at least 20 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised COG sheets identifying the amounts of the adjustments and the resulting currently effective COG rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant pipeline tariff sheets supporting costs claimed.

COST OF GAS – NATURAL GAS WAHPETON Rate 89

1. **Applicability:**
   This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under the Company's Wahpeton rate schedules in order to reflect: (a) changes in the Company's average cost of natural gas supply and (b) amortization of the Gas Cost Reconciliation account.

2. **Effective Date and Limitation on Adjustments:**
   (a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.

   (b) Montana-Dakota shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least $0.25 per dk. The adjustment to be effective June 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
   (a) The monthly COG shall reflect changes in Wahpeton's cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing.

   (b) Firm Demand - The average cost of demand for Wahpeton's firm gas sales shall be computed on the basis of current pipeline rates and contract demand divided by twelve-month weather normalized sales volumes applicable for the gas supply system serving Wahpeton and Minnesota customers.

   (c) Gas Commodity - The average weighted commodity cost, including transportation and other costs associated with the acquisition of gas, from all suppliers for the month the COG will be in effect.

   (d) Prepaid Commodity and Storage Balances – The return on prepaid commodity and storage balances shall be computed on an annual basis and shall be apportioned 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.

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

COST OF GAS – NATURAL GAS WAHPETON Rate 89

4. Gas Cost Reconciliation (GCR)

(a) For each twelve-month period ending April 30, a Gas Cost Reconciliation (GCR) will be calculated for each class set forth above. The GCR will be added to each customer class' cost of gas supply for the twelve-month period effective June 1 of each year. This adjustment shall include:

1. The balance in the (over) under recovered gas cost account as of April 30.
2. The difference between actual and recovered gas costs for each customer class for the twelve months ending April 30. The amount may be an under recovery or (over) recovery.
3. Demand costs recovered from the interruptible sales customers will be credited to the firm service customers.
4. Any refunds from suppliers of gas or pipeline services.
5. Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

(b) The resulting balance is divided by the projected dk sales for the next twelve months. The GCR adjustment shall be applied to the customers' monthly billings commencing on June 1 and remain in effective for a twelve (12) month period.

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$~~0.6860~~0.8919 per day
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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

~~**RESIDENTIAL PROPANE SERVICE Rate 90**~~

~~Reserved for Future Use~~

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

State of North Dakota
Gas Rate Schedule

FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

For customers with meters rated under 500 cubic feet per hour ~~Basic Service Charge:~~	
Basic Service Charge:	$0.75 per day
Distribution Delivery Charge:	$1.116 per dk
~~For customers with meters rated under 500 cubic feet per hour~~	~~$0.70 per day~~
For customers with meters rated over 500 cubic feet per hour	
Basic Service Charge:	$2.~~05~~13 per day
Distribution Delivery Charge:	$0.~~811~~887 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of propane as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane 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.

Date Filed:	~~October 5, 2018~~August 26, 2020	**Effective Date:**	~~Service rendered on and after December 1, 2018~~
Issued By:	~~Tamie A. Aberle~~Travis R. Jacobson Director – Regulatory Affairs	**Case No.:**	PU-~~17-295~~20-___

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

State of North Dakota
Gas Rate Schedule

FIRM GENERAL PROPANE SERVICE Rate 92

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed:	~~October 5, 2018~~August 26, 2020	**Effective Date:**	~~Service rendered on and after December 1, 2018~~
Issued By:	~~Tamie A. Aberle~~Travis R. Jacobson Director – Regulatory Affairs	**Case No.:**	PU-~~17-295~~20-___

1. **Availability:**
   This rate schedule constitutes a Cost of Gas (COG) provision and specifies the procedure to be utilized to adjust the rates for propane gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of propane supply, (b) amortization of the Unrecovered Purchased Cost of Gas Account and (c) grain drying margin sharing.

2. **Effective Date and Limitation on Adjustments:**
   (a) The effective dates of the COG shall be service rendered on and after the first day of each month, unless the Commission shall otherwise order.

   (b) Montana-Dakota shall file to reflect changes in its average cost of propane supply only when the amount of such change in COG is at least twenty-five (25) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
   (a) The monthly COG shall reflect changes in Montana-Dakota's cost of propane supply as compared to the cost of propane supply approved in its most recent COG filing. The cost of propane supply shall include, but not be limited to, all commodity and transportation charges incurred by Montana-Dakota for such propane supply.

   (b) The propane commodity cost shall reflect all commodity related propane costs estimated to be incurred for the month the COG will be in effect and estimated dk purchases.

   The unit cost per dk for the month shall be the commodity costs divided by estimated dk purchases for the month.

4. **Surcharge Adjustment:**
   All propane sales schedules shall be subject to a Surcharge Adjustment to be effective on May 1 each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Cost of Gas 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 Purchased Gas Account:**

(a) Items to be included in the Unrecovered Purchased Gas Account (Account 191), as calculated in accordance with Subsection 5(b) are:

(1) Charges for propane supply which Montana-Dakota is unable to reflect in the COG by reason of the twenty-five cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for propane supplies that were paid during any period after the effective date of the most recent approved rates, but not yet included in propane sales rates.

(3) Carrying charges or credits.

(b)

(1) The amount to be included in Account 191 in order to reflect the items specified in Subsections 5(a)(1) and (2) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's propane supply.

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

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each propane rate schedule. The resulting amounts shall be reflected in an Account 191 for each rate schedule.

Montana-Dakota will calculate carrying charges on the amounts in Account 191 as follows:

Each month, Account 191 shall be debited (on a debit balance) or credited (on a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

(i) The balance on 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 three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The carrying charges shall be accrued in a supplementary Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 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. 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 Account 191 specified in Subsections 5(a)(1) and (2) and the amounts in the supplementary Account 191 specified in Subsection 5(b)(2)(ii).

6. Grain Drying Margin Sharing Mechanism:
At the time of each surcharge adjustment, pursuant to Paragraph 4 of Rate 88, the Company will compute a credit to Rates 90 and 92 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service rates as established in Case No. PU-13-803, including prior period over or under collected balances.

7. Time and Manner of Filing:
(a) Montana-Dakota shall file each COG at least 10 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised COG sheets identifying the amounts of the adjustments and the resulting currently effective COG rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant material supporting costs claimed.

TABLE OF CONTENTS
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 Service Commission of North 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 Service Commission of the State of North 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 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.

EXCESS FLOW VALVE – Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.

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

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, 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 OBLIGATION:**

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 person 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 required to make a deposit as required by the Company.

2. SERVICE AVAILABILITY – Gas will normally be delivered at standard pressures of four to six ounces, dependent on the service territory where the gas service is being delivered. Delivery of gas service at pressures greater than the standard operating pressure may be available and will require a consultation with the Company to determine availability.

3. 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 ensure that such

equipment will conform to the Company's ability to adequately serve such installations with gas.

4. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises Monday through Friday, 8:00 a.m. to 5:00 p.m., unless an emergency requires access outside of these hours, for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

5. 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.

6. 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.

7. 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 or permits.

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

9. TERMINATION OF 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.

10. 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.

11. QUALITY OF GAS – The gas tendered to the Company shall conform to the applicable quality specifications of the transporting Pipeline's tariff.

IV. **LIABILITY**

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

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. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on the customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues and appliances on the customer's side of the point of delivery.

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, 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 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 authorization 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 with separate cooking facilities. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes with separate meters and sorority and fraternity houses. In addition, auxiliary buildings on the same premise as the living quarters when used for residential purposes may be served on the residential rate. This is not an all-inclusive list.

   (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 salons, 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 Homes 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.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with the following criteria:
   (a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   (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 be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. 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.

   A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.

   Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for twelve months, provided prompt payment record 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) Interruptible sales and transportation service customers agree to provide the cost of the installation of remote data acquisition equipment; as required, to the Company before service is implemented as provided for in the applicable rate schedule.

(c) 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, provided the equipment shall not interfere with such delivery or with the Company's meter.

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 (60ºF). 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, supercompressibility calculation. For handbilled accounts, application of supercompressibility factors will be waived on monthly-billed volumes of 250 dk or less.

Local sales base pressure is defined as four to six ounces (depending on service area) per square inch gauge pressure plus local average atmospheric pressure.

10. BILLING ADJUSTMENTS –
    (a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as Residential Service Rates 60, 63 or 90, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as non-residential (gas service provided under all rate schedules other than Rates 60, 63, or 90), the Company may adjustment back and rebill the bills in error for a period not to exceed six years.

    (d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and

refund the customer the amount of the overbilled for a period not to exceed six years from the date of payment.

11. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY – Priority of Service from Highest to Lowest:
    (a) Priority 1 – Firm sales services.
    (b) Priority 2 – Small interruptible sales at the maximum rate on a pro rata basis.
    (c) Priority 3 – Small interruptible sales at less than the maximum rate from the highest rate to the lowest rate on the pro rata basis where equal rates are applicable among customers.
    (d) Priority 4 – Large interruptible sales at the maximum rate on a pro rata basis.
    (e) Priority 5 – Small interruptible transportation services from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    (f) Priority 6 – Large interruptible transportation services from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    (g) Priority 7 – Gas scheduled to clear imbalances.

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

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

12. EXCESS FLOW VALVE – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.

13. 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 percent per month will be applied to any past due balance, 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.

14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for any check for any reason not honored by customer's bank.

15. MANUAL METER READING CHARGE– A monthly Manual Meter Reading Charge of $26.05 per month will be assessed customer(s) who have requested, and received Company approval, to have their meter read manually each month in lieu of an AMR-equipped meter read. Customer(s) agree to contract for the manual reading of the meter for a minimum period of one year.

16~~5~~. 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 customer's 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.

17~~6~~. 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 fumes.

(3) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

(4) Maintenance or repair of Company-owned facilities on the customer's premises.

(5~~4~~) Pilot relights necessary due to an interruption in gas service deemed to be the Company's responsibility.

(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) High bills or inadequate service complaints.

(3) Location of underground Company facilities for contractors, builders, plumbers, etc.

18~~7~~. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.

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.

To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

19~~8~~. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service disconnected shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, or telephone call to the Company's Customer Service Center. Saturdays, Sundays and legal holidays are not considered business days.

20~~19~~. 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.

21~~0~~. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER – A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee as follows:

Residential - The Basic Service Charge applicable during the period service was not being used and a charge of $30.00. The minimum will be based on standard overtime rates for reconnecting service after normal business hours.

Non-Residential – The Basic Service Charge applicable during the period while service was not being used. However, the reconnection charge applicable to seasonal business concerns such as irrigation, swimming facilities, grain drying and asphalt processing shall be the Basic Service Charge applicable during the period while service was not being used less the Distribution Delivery Charge revenue collected during the period in-service for usage above the annual authorized usage by rate class (Small Firm General Rate 70 = ~~188~~174 dk; Large Firm General Rate 70 = ~~1272~~1,220 dk; Small Firm General Rate 73 = 231 dk; Large Firm General Rate 73 = 525 dk; Small Firm General Propane Rate 92 = ~~173~~170 dk; Large Firm General Propane Rate 92 = ~~2089~~1,898 dk; and Small Interruptible = ~~6227~~5,918 dk). A reconnection fee of $30.00 will also apply to reconnections. The minimum will be based on standard overtime rates for reconnecting service occurring after normal business hours.

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

2~~1~~2. 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. For calls received after 12:00 p.m. on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

2~~2~~3. 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.

~~(b)~~(c) For violation of or noncompliance with the Company's rules on file with the Commission

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

~~(d)~~(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.

24~~3~~. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as tampering with a Company meter, pressure regulator, registration, connections, equipment, seals, procedures or records that result in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service that has been terminated, without the Company's consent.

(a) Examples of unauthorized use of service includes but is not limited to, tampering or unauthorized reconnection by the following methods:
  (1) Bypass piping around meter.
  (2) Bypass piping installed in place of meter.
  (3) Meter reversed.
  (4) Meter index disengaged or removed.
  (~~3~~5) Service or equipment tampered with or piping connected ahead of meter.
  (~~4~~6) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
  (~~5~~7) Gas being used after service has been discontinued by the Company. 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) In the event that there has been unauthorized use of service, customer shall be charged for:
   (1) Time, material and transportation costs used in investigation.
   (2) Estimated charge for non-metered gas.
   (3) On-premise time to correct situation.
   (4) Any damage to Company property.
   (5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.

(c) Reconnection of Service:
   Gas ~~S~~service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service, and paid any service charges which are due, including:
   (1) All delinquent bills, if any.
   (2) The amount of any Company revenue loss attributable to said tampering.
   (3) Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in number 20.b above.
   (4) Reconnection fee applicable.
   (5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

~~22.~~ 25. BILL DISCOUNT FOR QUALIFYING EMPLOYEES – A bill discount may be available for residential use only in a single family unit served by Montana-Dakota to qualifying retirees of MDU Resources and its subsidiaries. The bill shall be computed at applicable rate and the amount reduced by 33 1/3 percent.

~~23.~~26. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:

Rate 119 – Interruptible Gas Service Extension Policy
Rate 120 – Firm Gas Service Extension Policy
Rate 124 –Replacement, Relocation and Repair of Gas Service Lines

~~Reserved for Future Use~~

GAS METER TESTING PROGRAM Rate 105

Applicability:

This rate schedule specifies the protocol to be followed for the testing of gas meters in compliance with Sections 69-09-01-14 and 69-09-01-16 of the North Dakota Century Code.

Testing Process for New Meters

1. Meter supplier(s) shall provide test data for all new meters.

2. A sampling of 5% of new meter lots received will be tested at full load and light load. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or the shipment shall be returned to the manufacturer.

Testing Process for Meters in Service

1. This meter test schedule shall not apply to meters larger than 650 cubic feet per hour (cfh). Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.

2. All active meters, 650 cfh and smaller, will be combined into a single random test program. The population of meters shall come from the states of North Dakota, Montana, South Dakota, and Wyoming.

3. At the time the random selection is made, meters more than ten years old and active meters that have not been tested in the last ten years will be placed into an installation class defined model installation date lot (lot) to be part of a random population for testing.

4. All active meters will be assigned to lots on the basis of installation date. Meters shall be divided into lots based on manufacturer, type, and last install date in five year groups. The minimum number of samples taken from each lot will be as specified by Military Standard 414, Sample Procedures and Tables for Inspection by Variables for Percent Defective, inspection level IV with specification limits of + 2.0%.

GAS METER TESTING PROGRAM Rate 105

5. The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.

6. Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable quality level of 15%. The following actions will be taken based on the test results:

   a. A meter for which the sample is satisfactory will remain in service.

   b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.

   c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% of the sample registers over 102%

      i. If evaluation determines the group is homogeneous, then the entire group will be removed.

      ii. If group is not homogeneous and a subset of the group is found defective, that subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.

Reporting

Montana-Dakota shall file reports of its meter test results by December 1 for the meter testing conducted between June 30 of the previous year and July 1.

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 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, service line(s), regulators, meters, 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. Remote data acquisition equipment cost's shall be subject to the terms and conditions specified in the applicable interruptible service rate schedule.

   (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, or letter of credit, 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 shall pay the Company for such contribution requirement. ~~, or~~

   (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.

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's, 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 or letter of credit, will be notified of any reduction in surety 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 (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.

(d) The Company and customer may enter into a contract providing for a refund mechanism based on customer meeting identified minimums on the basis of specific extension characteristics.

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm sales 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 ~~¶A.~~paragraph 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 or Demand Charge)/LARR

   where: LARR = Levelized Annual Revenue Requirement Factor of ~~13.807~~12.757%

4. Cost of the extension shall include the gas main extension(s), valves, service line(s), any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs up to, and including, the riser.

   The service line is that portion of the gas service extending from the gas 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 ~~¶ A.~~paragraph 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. A minimum annual charge set forth in an agreement between customer and Company, or
      iv. Customer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state,

or letter of credit, 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 exits in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement.

(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 volumes 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. Customers who have posted a bond or letter of credit, will be notified of any reduction in surety requirements.

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

FIRM GAS SERVICE EXTENSION POLICY Rate 120

(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 a project consisting of 10 or more customers requesting service when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. If the Company and customers mutually agree that the project will be funded through a Surcharge, the project will be designated an expansion area and the Surcharge will be applicable to all connections within the expansion area. 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.~~paragraph 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 in a five-year period.

(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 a mobile home court, in which a developer is installing roads, utilizes, 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 ~~¶A.~~paragraph 3.

(b) The contribution shall be made by:

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

ii. Developer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state or, letter of credit 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.

(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. Developers who have posted a bond, or a letter of credit will be notified of any reduction in surety 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.

REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

1. 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.), the customer shall be charged for on the basis of direct costs incurred by the Company.

2. 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 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.

3. 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 the Firm Gas Service Extension Policy - Rate 120.

~~TABLE OF CONTENTS~~

~~Title~~	~~Sheet No.~~

~~GREAT PLAINS NATURAL GAS CO.~~

~~A Division of Montana-Dakota Utilities Co.~~

~~State of North Dakota~~
~~Gas Rate Schedule~~

~~NDPSC Volume 2~~

~~168th Revised Sheet No. 1.1~~

~~RATE SUMMARY SHEET~~ ~~Canceling 167th Revised Sheet No.1.1~~

~~Page 1 of 1~~

~~Rate Schedule~~	~~Sheet No.~~	~~Basic Service Charge~~	~~Distribution Delivery Charge~~		~~COG Items~~	~~Total Rate/dk~~
~~Firm Gas Service - General Rate 65~~	~~2~~	~~$3.50 per month~~	~~First 10 dk~~ ~~Over 10 dk~~	~~$1.0720~~ ~~0.8220~~	~~$2.3219~~	~~$3.3939~~ ~~3.1439~~
~~Interruptible Gas Service - General Rate 71~~	~~3~~	~~$3.50 per month~~	~~(Maximum)~~ ~~First 400 dk~~ ~~Next 2,600 dk~~ ~~Over 3,000 dk~~	 ~~$1.0160~~ ~~0.7675~~ ~~0.6140~~	~~$2.0610~~	~~(Maximum)~~ ~~$3.0770~~ ~~2.8285~~ ~~2.6750~~
~~Transportation Service Rate 80~~	~~5~~	~~$3.50 per month~~	~~(Maximum)~~ ~~First 400 dk~~ ~~Next 2,600 dk~~ ~~Over 3,000 dk~~	 ~~$1.0160~~ ~~0.7675~~ ~~0.6140~~		~~(Maximum)~~ ~~$1.0160~~ ~~0.7675~~ ~~0.6140~~

~~**Availability:**~~

~~Service under this schedule is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. See Rate 100 §III.2 for availability of firm gas service. Service under this rate shall not be subject to curtailment or interruption.~~

~~**Rate:**~~

~~Basic Service Charge:~~		~~\$3.50 per month~~
~~Distribution Delivery Charge:~~		
~~First~~	~~10 dk/month~~	~~\$1.072 per dk~~
~~Excess of~~	~~10 dk/month~~	~~\$0.822 per dk~~
~~Cost of Gas:~~		~~Determined Monthly – See Rate Summary Sheet for Current Rate~~

~~**Minimum Bill:**~~

~~Basic Service Charge~~

~~**Cost of Gas:**~~

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

~~**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.13, or any amendments or alterations thereto.~~

~~**General Terms and Conditions:**~~

~~The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.~~

~~**INTERRUPTIBLE GAS SERVICE – GENERAL Rate 71**~~

~~**Availability:**~~

~~Service under this schedule is available on an interruptible basis to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk and who have satisfied Great Plains Natural Gas Co. of their ability and willingness to discontinue the use of said gas during the period of curtailment or interruption, by the use of standby facilities or suffering plant shut-down. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in firm service agreement. The firm service volumes are subject to available capacity. Customer's firm load shall be billed at Firm Gas Service – General Rate 65. For interruptible purposes, the maximum daily firm requirements shall be set forth in the firm service agreement.~~

~~**Rate:**~~

~~Basic Service Charge:~~			~~$3.50 per month~~	
~~Distribution Delivery Charge:~~			~~Maximum~~	~~Minimum~~
~~First~~	~~400~~	~~dk/month~~	~~$1.0160 per dk~~	~~$0.130 per Dk~~
~~Next~~	~~2,600~~	~~dk/month~~	~~$0.7675 per dk~~	~~$0.130 per Dk~~
~~Excess of~~	~~3,000~~	~~dk/month~~	~~$0.6140 per dk~~	~~$0.130 per Dk~~
~~Cost of Gas:~~			~~Determined Monthly – See Rate Summary Sheet for Current Rate~~	

~~**Minimum Bill:**~~

~~Basic Service Charge~~

~~**Cost of Gas:**~~

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

~~**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.13, or any amendments or alterations thereto.~~

~~**INTERRUPTIBLE GAS SERVICE – GENERAL 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 rate, 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.11.~~

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 Gas Service – General Rate 65 (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.~~

3. ~~AGREEMENT – Customer will be required 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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(s) caused by customer's action.~~

5. ~~METERING REQUIREMENTS –~~
   a. ~~Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.~~

   b. ~~Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.~~

      ~~Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.~~

6. ~~The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.~~

~~**INTERRUPTIBLE TRANSPORTATION SERVICE Rate 80**~~

~~**Availability:**~~

~~Service under this rate schedule is available on an interruptible basis to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk and who have satisfied Great Plains Natural Gas Co. of their ability and willingness to discontinue the use of said gas during the period of curtailment or interruption, by the use of standby facilities or suffering plant shut-down. This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through the Company's distribution facilities. To obtain transportation service, a customer must meet the general terms and conditions of service provided hereunder and enter into a gas transportation agreement upon request of the Company.~~

~~**Rate:**~~

~~Basic Service Charge: $3.50 per month~~

~~Distribution Delivery Charge:~~		~~Maximum~~	~~Minimum~~
~~First~~	~~400 dk/month~~	~~$1.0160 per dk~~	~~$0.130 per Dk~~
~~Next~~	~~2,600 dk/month~~	~~$0.7675 per dk~~	~~$0.130 per Dk~~
~~Excess of~~	~~3,000 dk/month~~	~~$0.6140 per dk~~	~~$0.130 per Dk~~

~~Customers shall pay Basic Service Charge plus a negotiated rate not to exceed the maximum rate or less than the minimum rate specified above.~~

~~**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.13, or any amendments or alterations thereto.~~

~~**General Terms and Conditions:**~~

1. ~~CRITERIA FOR SERVICE: In order to receive transportation service, customer must qualify under the Company's applicable natural gas transportation service rate 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. ~~Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.~~

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 under the Firm Gas Service – General Rate 65 (distribution delivery charge and cost of gas). 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.11.~~

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 customer's behalf, shall be billed at the Firm Gas Service – General Rate 65 (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.~~

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 charged at the Firm Gas Service – General Rate 65 (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 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.~~

   ~~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.~~

8. ~~DAILY IMBALANCE – 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.~~

   ~~In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.~~

   ~~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.~~

9. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

   a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

   Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 9(c).

   b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

~~Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 9(c).~~

c. ~~The Index Price shall be the arithmetic average of the "Weekly Weighted Average Prices" published by Gas Daily for Emerson, Manitoba during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.~~

~~10. METERING REQUIREMENTS:~~

a. ~~Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.~~

b. ~~Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.~~

~~Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.~~

~~11. DAILY NOMINATION REQUIREMENTS:~~

a. ~~Customer or customer's shipper or agent shall advise Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC time lines, of the dk requirements customer has requested to be delivered at each delivery point 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.~~

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

~~12. 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.~~

~~13. 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.~~

14. ~~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.13, or any amendments or alterations thereto.~~

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

16. ~~The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.~~

~~COST OF GAS – NATURAL GAS RATE 88~~

~~1. Applicability:~~

~~This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under Great Plains rate schedules in order to reflect: (a) changes in Great Plains' average cost of natural gas supply and (b) amortization of the Gas Cost Reconciliation account.~~

~~2. Effective Date and Limitation on Adjustments:~~

~~(a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.~~

~~(b) Great Plains shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least $0.25 per dk. The adjustment to be effective June 1 shall be filed each year, regardless of the amount of the change.~~

~~3. Cost of Gas:~~

~~(a) The monthly COG shall reflect changes in Great Plains' cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing.~~

~~(b) Firm Demand - The average cost of demand for Firm Gas Sales shall be computed on the basis of current pipeline rates and contract demand divided by twelve month weather normalized sales volumes applicable for the entire Great Plains' gas system.~~

~~(c) Gas Commodity - The average weighted commodity cost, including transportation and other costs associated with the acquisition of gas, from all suppliers for the month the COG will be in effect.~~

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

~~4. Gas Cost Reconciliation (GCR)~~

~~(a) For each twelve-month period ending April 30, a Gas Cost Reconciliation (GCR) will be calculated for each class set forth above. The GCR will be added to each customer class' cost of gas supply for the twelve-month period effective June 1 of each year. This adjustment shall include:~~

1. ~~The balance in the (over) under recovered gas cost account as of April 30.~~
2. ~~The difference between actual and recovered gas costs for each customer class for the twelve months ending April 30. The amount may be an under recovery or (over) recovery.~~
3. ~~Demand costs recovered from the interruptible sales customers will be credited to the firm general service customers.~~
4. ~~Any refunds from suppliers of gas or pipeline services.~~
5. ~~Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.~~

~~(b) The resulting balance is divided by the projected dk sales for the next twelve months. The GCR adjustment shall be applied to the customers' monthly billings commencing on June 1 and remain in effective for a twelve (12) month period.~~

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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 Service Commission of North 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 Service Commission of the State of North Dakota.~~

~~COMPANY – Great Plains Natural Gas 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.~~

~~EXCESS FLOW VALVE - Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.~~

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

~~INTERRUPTIBLE CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency that will cease the use of natural gas or transportation service when deemed necessary by Company.~~

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

~~NOMINATION – The daily 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.~~

2. ~~INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,000,000 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 ensure 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 8 a.m. to 5 p.m. Monday – Friday unless an emergency situation requires access outside of these hours 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.~~

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, 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 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.~~

10. ~~QUALITY OF GAS – The gas tendered to the Company shall conform to the applicable quality specifications of the transporting pipeline's tariff.~~

~~IV. LIABILITY:~~

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

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, devices owned, installed or maintained by the customer or leased by the customer from third parties. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues, and appliances on the customer's side of the point of delivery.~~

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 authorization 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. 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. ~~SERVICE FACILITIES ON CUSTOMER PREMISES – The Company shall furnish, own, and maintain all material and equipment to the outlet side of the meter on the customer's premises. Customer shall pay an installment or connection charge based upon the following rates:~~

~~(a) New Service Line Construction:~~

~~(1) Minimum connecting charge, per meter, covering the cost of service connection, general inspection, and gas turn-on and payable at the time of sign-up is $25.00 for customers with gas input loads up to 400,000 Btu/hour; $50.00 for customers with gas input loads above 400,000 Btu/hour and $100.00 for interruptible customers.~~

~~(2) Service line installation charges shall be based upon the lesser of the Company's labor and material rates or the current cost per foot.~~

~~Length of service line shall be determined by measurement made from customer's property line to stop value on the service riser.~~

~~(b) Additional meters to existing service lines and inactive line connections:~~

~~A $25.00 connection charge covering the cost of service connection, general inspection, and gas turn-on will be collected at time of application from each individual requesting an additional meter to an existing service line or connection to an inactive line.~~

~~(c) Relocation of Existing Meters and Service Lines:~~

~~When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and material rates.~~

4. ~~TEMPORARY SERVICE – At the discretion of the Company, temporary service may be rendered to a customer's premise. The Company may require the customer to bear the cost of installing and removing the service~~

~~in excess of any salvage realized. Advance installation payment may be required prior to installing the service.~~

~~The customer shall pay the regular rates applicable to the class of service rendered.~~

~~5. 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.~~

~~6. 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 Homes 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.~~

~~7. 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 and one-half times the estimated amount of one month's average bill.~~

~~(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 be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. 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.~~

~~A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the customer's account annually during the month of December.~~

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

~~8. 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) Interruptible sales and transportation service customers agree to provide the cost of the installation of remote data acquisition equipment; as required, to the Company before service is implemented as provided in the applicable rate schedule.~~

~~9. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be (1) dekatherm (dk), unless otherwise specified. One dk equals 10 therms or 1,000,000 Btu's. Dk 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.~~

~~10. 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 (60ºF). 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, supercompressibility calculation.~~

~~Local sales base pressure is defined as five ounces per square inch gauge pressure plus local average atmospheric pressure.~~

~~11. PRIORITY OF SERVICE – Priority of Service from Highest to Lowest:~~
~~(a) Priority 1 – Firm sales services.~~
~~(b) Priority 2 – Interruptible sales and interruptible transportation services.~~
~~(c) Gas scheduled to clear imbalances.~~

~~Company 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 Company system.~~

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

~~12. EXCESS FLOW VALVES – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.~~

~~13. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill, or 22 days from date of bill. An amount equal to 1 1/3% per month will be applied to any unpaid balance if not paid by the due 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.~~

~~14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for each check charged back to the Company by a bank.~~

~~15. 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 customer's 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.~~

~~16. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.~~

~~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.~~

~~To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply if service is required that day~~

~~and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.~~

~~17. NOTICE TO DISCONTINUE GAS SERVICE – Customers desiring to have their gas service disconnected shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, or telephone call to the Company's Customer Service Center. Saturdays, Sundays and legal holidays are not considered business days.~~

~~18. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee of $30.00.~~

~~Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a minimum reconnection charge of $160.00 whenever reinstallation of the required 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 $30.00 before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.~~

~~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 such as tampering with a Company meter, pressure regulator, registration, connections, equipment, seals, procedures or records that result in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service that has been terminated, without the Company's consent.~~

~~(a) Examples of unauthorized use of service include the following, but are not limited to:~~

~~(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) In the event that there has been unauthorized use of service, customer shall be charged for:~~

~~(1) Time, material and transportation costs used in investigation.~~
~~(2) Estimated charge for non-metered gas.~~
~~(3) On-premise time to correct situation.~~
~~(4) Any damage to Company property.~~
~~(5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.~~

~~(c) Customer service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid all charges as hereinafter set forth in this procedure.~~

~~(1) All delinquent bills, if any.~~
~~(2) The amount of any Company revenue loss attributable to said tampering.~~
~~(3) Expenses incurred by the Company in replacing or repairing the meter or other appliance costs incurred in preparation of the bill, plus costs as outlined in number 21.b above.~~
~~(4) Reconnection fee equal to the Company's minimum service charge.~~

~~(5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.~~

~~22. BILLING ADJUSTMENTS –~~

~~(a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.~~

~~(b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service was provided under Rate 65, the Company may adjust back and rebill the bills in error for a period not to exceed six months.~~

~~(c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where service was provided under an interruptible service schedule, the Company may adjustment back and rebill the bills in error for a period not to exceed six years.~~

~~(d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and refund the customer the amount of the overbilled.~~

~~**Applicability:**~~

~~This rate schedule specifies the protocol to be followed for the testing of gas meters in compliance with Sections 69-09-01-14 and 69-09-01-16 of the North Dakota Century Code.~~

~~**Testing Process for New Meters**~~

1. ~~Meter supplier(s) shall provide test data for all meters.~~

2. ~~A sampling of 5% of new meter lots received will be tested at full load and light load. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or shipment shall be returned to the manufacturer.~~

~~**Testing Process for Meters in Service:**~~

1. ~~This meter test schedule shall not apply to meters larger than 650 cubic feet per hour (cfh). Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.~~

2. ~~All active meters, 650 cfh and smaller will be combined into a single random test program. Great Plains meters shall be combined with Montana-Dakota Utilities Co. meters for purposes of random sample testing only.~~

3. ~~At the time the random selection is made, meters more than ten years old and active meters that have not been tested in the last ten years will be placed into an installation class defined model installation date lot to be part of a random population for testing.~~

4. ~~All active meters rated at 650 CFH and smaller, will be assigned to lots on the basis of installation date. Meters shall be divided into lots based on manufacturer, type, and last install date in five year groups. The minimum number of samples taken from each lot will be as specified by Military Standard 414, Sample Procedures and Tables for Inspection by Variables for Percent Defective, inspection level IV with specification limits of +2.0%.~~

5. ~~The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.~~

6. ~~Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable~~

~~quality level of 15%. The following actions will be taken based on the test results:~~

~~a. A meter for which the sample is satisfactory will remain in service.~~

~~b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.~~

~~c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% if the sample registers over 102%~~

~~i. If evaluation determines the group is homogeneous, then the entire group will be removed.~~

~~ii. If group is not homogeneous and a subset of the group is found defective, the subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.~~

~~**Reporting:**~~
~~Great Plains shall file reports of its meter test results by December 15 for the meter testing conducted for the previous calendar year.~~

~~GREAT PLAINS NATURAL GAS CO.~~

~~*A Division of Montana-Dakota Utilities Co.*~~

~~**State of North Dakota**~~

~~Gas Rate Schedule~~

~~NDPSC Volume 2~~
~~Original Sheet No. 11~~

~~FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105~~

~~The Company will install gas main extensions using the following guidelines applicable to firm gas main extensions:~~

a) ~~The term "main" refers to the facilities that are typically constructed from a border station or regulator station with no particular terminus at a building or structure. Mains are normally installed in streets, alleys, dedicated public ways or dedicated utility easements.~~

b) ~~Customer refers to customer ultimately taking natural gas service or a developer request to provide natural gas service to residential customers.~~

c) ~~Cost Participation. Cost participation for firm gas extensions shall be determined as follows:~~

   i) ~~Extensions 95 Feet or Less – The Company will extend a gas main up to, but not to exceed, 95 feet per home projected to be connected within twelve (12) months from the start of construction where natural gas is the primary fuel used for space heating.~~

   ii) ~~Extensions over 95 Feet or where natural gas in not the primary fuel used for space heating – The Company may require cost participation if the estimated capital expenditure is not cost justified. The extension will be considered cost justified if the calculated Maximum Allowable Investment equals or exceeds the estimated capital expenditures using the following formula:~~

~~Maximum Allowable Investment (MAI) =~~

~~Annual Basic Service Charge +~~

~~(3rd Year Estimated Dk x Distribution Delivery Charge)/LARR~~

~~Where: LARR = 11.626%~~

~~The LARR, defined as the Levelized Annual Revenue Requirement Factor, is the annual rate required to recover the present value of a project over the life of a project.~~

~~**FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105**~~

~~d) Cost of the extension shall include the gas main extension(s), valves, service line(s), cathodic protection equipment, 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.~~

~~e) Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer.~~

~~f) Contributions. In the event the extension is not cost justified, the customer(s) shall pay the Company the portion of the capital expenditures not cost justified. The extension will proceed if the customer:~~

~~i) Pays in advance to the Company the excess amount not cost justified in cash, or~~

~~ii) Agrees to pay a special monthly charge. If the customer discontinues service prior to the excess being paid in full, the balance will be due and payable upon discontinuance of service, or~~

~~iii) Agrees to pay annually a specified minimum charge. If the customer discontinues service prior to the excess being paid in full, the balance will be due and payable upon discontinuance of service, or~~

~~iv) Agrees to a combination of above methods, or~~

~~v) Customer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction and acceptable by the Company. Such bond, issued by a bonding company authorized to do business in the state or letter of credit 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.~~

~~**FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105**~~

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

~~vii) If within the five year period from the extension(s) in service date, the number of active customers and related volumes exceeds the projections used to determine MAI, the Company shall re-compute the contribution requirement by recalculating the MAI.~~

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

~~g) Refunds. Contributions for gas main extensions are refundable, without interest, for a period up to five (5) years from the date of completion of the main extension as additional customers are connected to the particular main extension for which the advance was made.~~

~~i) The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. Customers who have posted a bond or letter of credit will be notified of any reduction in surety or guarantee requirements.~~

~~ii) No refunds will be made until the new applicants begin taking service from the Company.~~

~~iii) 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.~~

~~iv) No refund shall be made by Company after the five-year refund period and in no event shall the refund exceed the amount of the contribution.~~

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

~~i) Firm Gas Service Line Extensions:~~
~~The Company shall install gas service lines using the following general rules and regulations applicable to all firm gas service line extensions:~~

~~i) The term "service line" refers to facilities that are constructed from a main to the final terminus at a building or structure.~~

~~ii) The Company shall furnish, own, and maintain all material and equipment to the outlet side of the meter on the customer's premise(s).~~

~~iii) The Company will extend a service line to serve customer(s) where natural gas is the primary fuel used for space heating without charge up to, but not to exceed, 65 feet. The length of the service line shall be determined by measurement from the customer's property line to the stop valve on the service riser.~~

~~iv) If the additional service line required is beyond 65 feet or natural gas is not the primary fuel used for space heating, the Company may require cost participation if the estimated capital expenditure is not cost justified. The service line extension will be considered cost justified if the calculated MAI equals or exceeds the estimated capital expenditures using the MAI formula provided in ¶ c.ii.~~

~~v) Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer.~~

~~vi) Relocation of Existing Meters and Service Lines: When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and materials rates.~~

~~A minimum connection charge, per meter, covering the cost of the installation of the meter and regulator, the service connection, general inspection, and gas turn-on is payable at the time the application for service is submitted. The minimum connection charge is $25.00 per meter for customers with gas input loads up to 400,000 BTU/hour; and $50.00 per meter for customers with gas input loads above 400,000 BTU/hour.~~

~~**INTERRUPTIBLE GAS MAIN AND SERVICE LINE EXTENSIONS POLICY Rate 106**~~

~~The Company will install gas main and service line extensions using the following guidelines:~~

~~a) Contribution. Prior to construction, the customer shall contribute an amount equal to the total cost of construction including all gas main extensions, valves, service line(s), cathodic protection equipment, 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 applicable federal and state income taxes.~~

~~i) The extension will proceed if the customer:~~

~~(1) Pays in advance to the Company the total cost of construction, or~~

~~(2) Customer may post a bond or irrevocable letter of credit in the amount of the required contribution prior to construction and acceptable by the Company. Such bond, issued by a bonding company authorized to do business in the state or letter of credit 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.~~

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

~~iii) Remote data acquisition equipment costs shall be subject to the terms and conditions specified in the Company's Interruptible Gas Transportation Rates.~~

~~b) Refund. Contributions for gas main and service line extensions are refundable, without interest, for a period up to five (5) years from the date of completion of the main extension.~~

~~i) 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, the Company shall refund the amount exceeding the revenue requirement on the following basis:~~

~~(1) Annually, beginning at the second (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.~~

~~(2) Customers who have posted a bond or letter of credit will be notified of any reduction in surety or guarantee requirements based on the above calculation.~~

~~(3) No refund shall be made by Company after the five-year refund period and in no event shall the refund exceed the amount of the contribution.~~

~~ii) If within the five-year period from the extension(s) in service date, additional customers (firm or interruptible) are connected to an interruptible customer's main extension, the Company shall (1) determine the pro rata cost share applicable to the other customer (2) reduce the original customer's contribution requirement by the pro rata cost attributed to the new customer and (3) calculate an MAI for a firm customer through the process described in Rate 105 ¶ c.ii or collect the full amount for an interruptible customer. The amount collected will be subject to the applicable refund provisions for the remainder of the refund period.~~

~~c) Relocation of Existing Meters and Service Lines: When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and material rates.~~

~~d) A minimum connection charge, per meter, covering the cost of the installation of the meter and regulator, the service connection, general inspection, and gas turn-on is payable at the time the application for service is submitted. The minimum connection charge is $100.00 for interruptible customers.~~

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-20-___

Direct Testimony
of
Nicole A. Kivisto

Q. Please state your name and business address.

A. Yes. My name is Nicole A. Kivisto, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the President and Chief Executive Officer (CEO) of Montana-Dakota Utilities Co. (Montana-Dakota), and Great Plains Natural Gas Co. (Great Plains), a division of Montana-Dakota. I am also the President and CEO of Cascade Natural Gas Corporation and Intermountain Gas Company, all subsidiaries of MDU Resources Group, Inc., collectively the MDU Utilities Group, herein referred to collectively as "Company."

Q. Please describe your duties and responsibilities with MDU Utilities Group.

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above-mentioned companies that, in combination, serve over 1.1 million customers in eight states.

Q. Please outline your educational and professional background.

A. I hold a bachelor's degree in Accounting from Minnesota State University Moorhead. I began working for MDU Resources/Montana-Dakota in 1995 and have been in my current capacity since January 2015. I was the Vice President-Operations of Montana-Dakota and Great Plains from January of 2014 until assuming my present position.

Prior to that, I was the Vice President, Controller, and Chief Accounting Officer for MDU Resources for nearly four years and held other finance related positions prior to that.

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

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of Montana and Wyoming, the Public Utilities Commissions of Idaho, Minnesota, and South Dakota, the Public Utility Commission of Oregon, and the Washington Utilities and Transportation Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Company's gas operations in the state of North Dakota. I will also provide an overview of the Company's request for a natural gas distribution rate increase and discuss the policies and reasons underlying the major aspects of the request. Finally, I will address the need for an interim increase and introduce the other Company witnesses that will present testimony and exhibits in further support of the Company's request.

Q. Would you please address the relationship between Montana-Dakota and Great Plains Natural Gas Co. (Great Plains) and how that affects this rate case?

A. Yes. Great Plains is a Division of Montana-Dakota and operates as a district. Great Plains serves customers in Minnesota and the community of Wahpeton and the surrounding area in North Dakota. There are approximately 2,355 customers in North Dakota and its operations are currently managed in a manner similar to Montana-Dakota's other districts, such as Jamestown. In a Settlement in Case Nos. PU-17-490 and PU-17-075 approved by this Commission, the Parties agreed to begin combining all gas operations within North Dakota for reporting purposes as a first step to having one North Dakota gas utility operation. I will address steps proposed in this rate case to further align the service provided to Wahpeton under Montana-Dakota's tariff.

Q. Would you provide a summary of Montana-Dakota's and Great Plains' gas operations in North Dakota?

A. The Company currently provides natural gas service to approximately 115,000 customers in 75 communities in North Dakota, operating approximately 2,752 miles of distribution mains and approximately 115,953 service lines. The customer base is 86 percent residential and 14 percent commercial and industrial. As of December 31, 2019, the Company had 518 full and part-time employees who live and work throughout the Company's North Dakota electric and natural gas service area. Montana-Dakota's North Dakota natural gas service area is divided into two operating regions with regional offices located in Bismarck and Dickinson, North Dakota. In addition to the regional offices, there are fully staffed operations centers located in the communities of Minot, Williston, and Devils Lake, with satellite offices in Watford City and Jamestown. Great Plains' North Dakota natural gas service area is serviced out of Great Plains' office in Fergus Falls, Minnesota.

The Company's customers have toll-free access to the Customer Experience Team located at the Customer Service Centers in Meridian, Idaho, and Bismarck, North Dakota as well as the Credit Center in Bismarck, North Dakota, to place routine utility service requests and inquiries from 7:30 am to 6:30 pm local time, Monday through Friday and emergency calls on a 24-hour basis. A scheduling center, part of the Customer Experience Team located in Meridian, Idaho transmits electronic service orders to the mobile terminals placed in our fleet of service and construction vehicles. This network allows the Company to respond quickly to customer requests and emergency situations.

Q. Would you please provide more information regarding the customers the Company serves?

A. Yes. The residential, firm general service, and small interruptible customers use natural gas primarily for space and water heating. As such, the Company's system has a low load factor with peak gas requirements occurring during the winter with summer loads being small by comparison. The Company is projecting to deliver approximately 25.8 Mmdk of natural gas to customers in North Dakota in 2021. The natural gas requirements by customer class is as follows: approximately 34 percent residential, 33 percent firm general service, 13 percent small interruptible, 18 percent large interruptible, and 2 percent for the Air Force.

Q. Would you please describe the basic elements that make up the total costs of providing natural gas service?

A. For a natural gas distribution utility, the basic elements which make up the cost of providing natural gas service are the cost of gas delivered at the town border stations in its service territory and the cost of distributing the gas from the town border station to the end use customer. It is the second of these two elements, the distribution costs, which are the subject of this application for a general rate increase.

The natural gas the Company purchases from suppliers is a commodity like wheat or corn, the price of which is not regulated. The cost of delivering the gas to the Company's distribution system at the town border station is regulated by the FERC or other regulatory agencies. These gas costs are passed on to customers on a dollar-for-dollar basis as specified in the Commission approved Cost of Gas tariff. The gas portion of the cost of providing natural gas service comprises about 58 percent of a typical residential bill for natural gas service.

The distribution portion of the Company's cost of service is the subject of this proceeding. This element includes the costs of new distribution investments, replacement of aging infrastructure, operation and maintenance expenses, depreciation, taxes, and the opportunity to earn a return on the Company's investments in facilities that provide natural gas service. Distribution costs are currently about 42 percent of a typical residential bill.

Q. How is the COVID-19 pandemic impacting the Company and its customers?

A. The Company has implemented appropriate measures to ensure that it can continue to operate safely and ensure that the Company's customers can continue to receive essential gas service during this challenging time. To that end, the Company temporarily suspended the collection of late payment charges on April 1, 2020 for its customers and implemented a moratorium on service disconnections for non-payment related to hardships incurred from COVID-19 beginning mid-March and extending through the end of August 2020. The Customer Experience Team is working with customers to establish longer than normal repayment plans if appropriate and to ensure customers are aware of energy assistance programs available to them.

Q. Has the Company considered the impact of filing a general rate case during these trying times?

A. We understand that many of our customers may be experiencing economic hardship resulting from the COVID-19 pandemic, and that the prospect of a rate increase may be difficult at this time. We carefully considered the appropriate timing for this filing and ultimately determined that the rate increase is necessary in order to meet customers' needs in regard to maintaining safe and reliable service as well as provide timely recovery of the Company's investments and costs. While there is uncertainty regarding how long the Company and its customers will be impacted by the COVID-19 pandemic and the magnitude of the impacts, the Company is optimistic that the situation will be improved by the time rates go into effect in 2021 as explained later in my discussion of interim rates.

Q. Please summarize the requested increase in this filing.

A. The Company's cost of doing business in North Dakota is increasing despite the Company's efforts to control costs and increase efficiency.

The Company has invested approximately $11.0 million between 2017 and 2019 to improve the safety and reliability of its distribution system in North Dakota. While much progress was made over this period, the Company believes its necessary to maintain its focus on system improvements and estimates it will invest more than $43.1 million to ensure system safety and reliability between 2020 and 2024. Further, the Company continues to experience increases in labor and personnel costs and general cost increases across its business lines.

The Company's rate base growth and increased operating expenses since its last filed rate case require it to request an overall increase of $8,972,496 or 7.80 percent based on a projected 2021 test period. The Company's demonstrated increase is based on an overall rate of return of 7.304 percent based on a weighted capital structure of 50.306 percent common equity, 49.694 percent debt, and a return on equity of 10.2 percent.

Q. What other adjustments are contributing to the need for an increase in distribution rates?

A. In addition to the operating expenses, the Company is requesting the inclusion of the provision for pension and post-retirement benefits, net of the associated deferred taxes, to be added to rate base.

Q. Why has the Company proposed to include these assets and liabilities in rate base at this time?

A. Recent contributions to the Company's pension trust fund have resulted in a significant prepaid asset related to the Company's pension plan as shown in Table 1 below:

	Cash Contributions	Pension Expense	Pension Balance Debit (Credit)
Beginning Balance - 12/31/2004			$7,777,266
Activity - 2005	$0	$4,179,348	3,597,918
Activity - 2006	-	4,118,976	(521,058)
Activity - 2007	1,188,690	3,724,426	(3,056,794)
Activity - 2008	-	2,825,775	(5,882,569)
Activity - 2009	8,347,434	4,759,097	(2,294,232)
Activity - 2010	3,871,657	(5,328)	1,582,753
Activity - 2011	13,757,133	1,610,332	13,729,554
Activity - 2012	12,038,687	(740,118)	26,508,359
Activity - 2013	10,014,592	1,830,351	34,692,600
Activity - 2014	12,202,457	594,340	46,300,717
Activity - 2015	2,182,143	1,398,780	47,084,080
Activity - 2016	-	1,746,833	45,337,247
Activity - 2017	422,015	1,422,159	44,337,103
Activity - 2018	7,200,692	720,403	50,817,392
MDU R funding adj	(5,133,171)	-	45,684,221
Activity - 2019	15,452,375	1,379,116	59,757,480
Total Funding	$81,544,704	$29,564,490	
Ending Balance - 12/31/2019			$ 59,757,480

As shown in Table 1, the cash contributions made by the Company have significantly exceeded the pension expense, which is the amount included in the Company's revenue requirement and recovered through rates charged to customers. Similar to other investments, Montana-Dakota has a significant outlay in cash and its only opportunity to earn a return on the outlay of cash is by inclusion in the Company's rate base.

Montana-Dakota has taken a number of steps to minimize pension costs. They include closing the pension plan to new participants as well as freezing the level of benefits accrued. In addition, the Company's contributions generally result in lower pension expense recovered through the revenue requirement.

The post retirement prepaid asset, while much smaller in size, has similar characteristics as the prepaid pension asset and was included in the pro forma rate base as well.

Q. Ms. Kivisto, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota and Great Plains filed this application for a natural gas rate increase?

A. The Company is requesting an increase in its general gas rates at this time because the current rates do not reflect the cost of providing natural gas service to its North Dakota customers.

Q. When was the Company's last general rate case?

A. Montana-Dakota's last rate case was Case No. PU-17-295. The resulting rate increase including the effects of the Tax Cuts and Jobs Act of 2017 was $2.5 million, or a 2.30 percent overall increase. Final rates in that case became effective on December 1, 2018. Great Plains' last rate case was Case No. PU-17-490 and was a reduction of $168,306 resulting from the Tax Cuts and Jobs Act of 2017.

Q. What are the primary reasons that the Company needs an increase at this time?

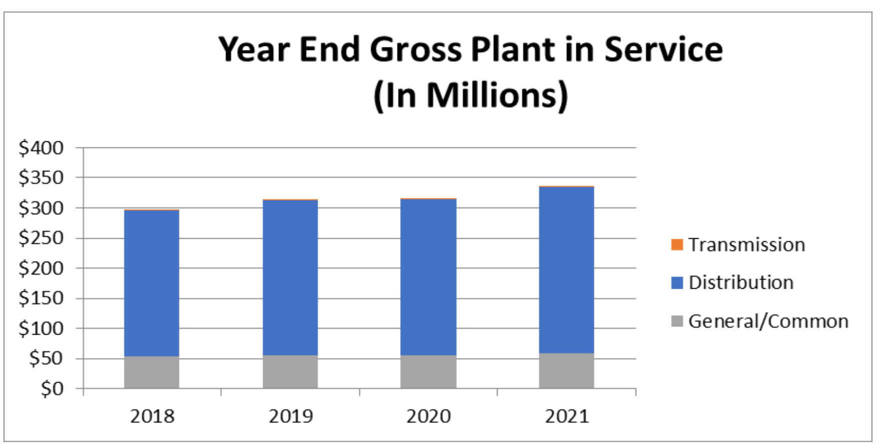
A. As noted earlier, the last Montana-Dakota rate increase was implemented December 1, 2018 and was based on a projected 2018 revenue requirement for North Dakota. The primary reason for the need for an increase in rates is the Company's continued investment in distribution facilities to improve system safety and reliability. The additional investment has generally increased the associated depreciation, taxes, and operation and maintenance expenses.

Q. Would you please describe the investment in distribution facilities to improve system safety and integrity in greater detail?

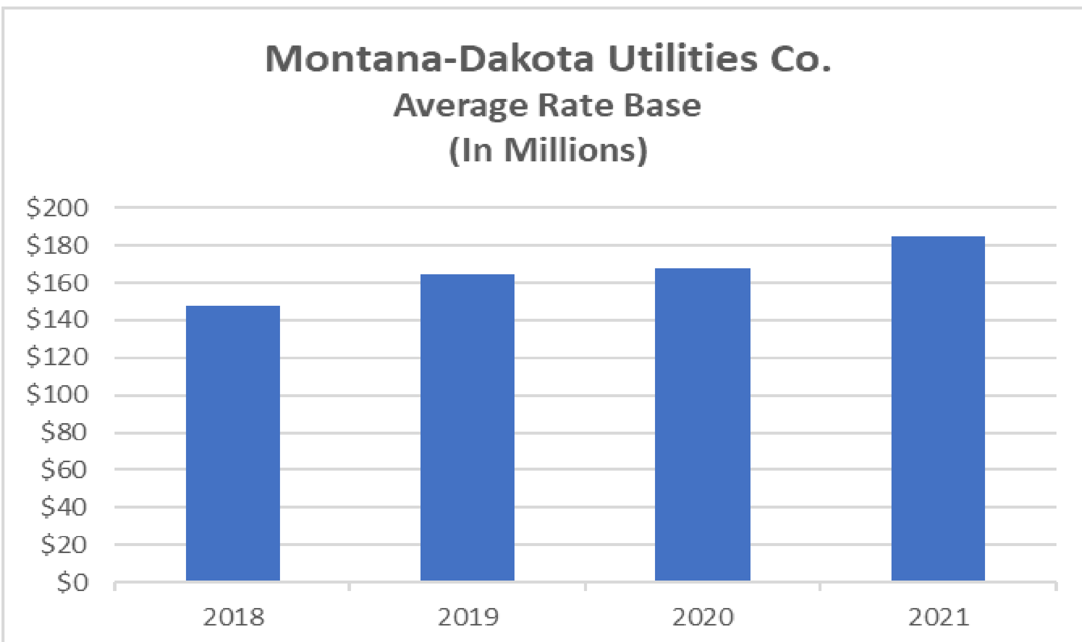
A. The investment in system safety and integrity is a focused effort based on the Company's Distribution Integrity Management Program (DIMP). Mr. Darras will explain in further detail how the DIMP is used to identify the pipeline replacement projects necessary for safety reasons and to reduce risk on Montana-Dakota's system.

Q. How much has the gross investment and rate base increased since the last case?

A. The table below shows the year end gross investment in natural gas plant assigned and allocated to North Dakota and Great Plains North Dakota gas operations. The year end gross investment projected for 2021 is $336 million or nearly 22 percent greater than the gross investment from the 2018 test year used in the last rate case.



The chart above illustrates the increase in the investment in plant in service since 2018. The increase in distribution plant is the largest contributor. At the same time, rate base has increased from $148.4 million to $184.7 million from 2018 to the 2021 projected test period. The addition of the pension and post retirement benefits regulatory assets has also contributed to the increase in rate base.



Q. Have increased operating expenses contributed to the need for this rate increase?

A. Yes, the Company's operating expenses, which include depreciation and taxes other than income, have increased since the last rate case. However, as mentioned earlier, the largest contributing factor has been the investment necessary to safely and adequately serve customers.

Q. Ms. Kivisto, would you explain how Montana-Dakota and Great Plains strives to efficiently provide safe and reliable service to its North Dakota customers?

A. The Company works hard to control its costs by continually looking for opportunities that create efficiencies and control costs. In spite of the Company's efforts to control costs, the Company is seeing a need for increased revenue as the need to replace existing infrastructure and add new infrastructure continues.

The MDU Utilities Group, which encompasses the four brands I discussed previously, has recently moved forward from a regional operations structure by brand to a functional approach across all brands covering an eight-state service area, striving for operational consistency.

The goal is to develop an operations organizational structure to operate as one utility with one vision:

- Create efficiencies in operations, technology and support services through common approaches and standards
- Gain economics of scale by using resources more effectively

- Streamline decision making
- Reduce duplication of effort
- Better manage the need for additional resources
- Implementation of a Pipeline Safety Management System
- Ensure the organization is better prepared for growth
- Evolution of continuous improvement
- Build specialized groups with a high level of expertise in their field

The functions are organized as follows, each reporting to a Vice President who oversees the function across all brands and eight states:

- **Field Operations (Eric Martuscelli - Vice President)**

  Directs and coordinates activities for the entire gas and electric distribution field operations across the eight-state service territory. Oversees the delivery of regulated products and services to our customers.

- **Operations and Engineering Services (Pat Darras - Vice President)**

  Oversees the development, design and execution of critical and transformative operational strategic initiatives including but not limited to asset management, infrastructure upgrades, and compliance while maintaining engineering and operational excellence across the MDU Utilities Group.

- **Safety, Process Improvement, and Operations Technology (Hart Gilchrest - Vice President)**

  Oversees the development, design and execution of critical and transformative operational excellence strategic initiatives including but not limited to safety, technical training, safety management systems, process improvement and operations technology.

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

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

Class	Percent
Residential	12.5%
Firm General	3.1%
Air Force	2.3%
Small Interruptible	2.5%
Large Interruptible	0.9%
Overall	7.8%

Based on the increase noted above, a residential customer would see an average increase of $6.26 per month.

Q. What return is Montana-Dakota and Great Plains requesting in this case?

A. The Company is requesting an overall return of 7.304 percent, inclusive of a return on equity (ROE) of 10.2 percent. Ms. Bulkley's analysis indicates that a 10.2 percent ROE is fully justified and supported based on the results of her studies.

Q. The Company is proposing a phased approach to combine Great Plains' gas operations in North Dakota with Montana-Dakota's gas operations. Will you please explain?

A. Yes. In this filing, the Company proposes to begin the phase in of Wahpeton's customers to become Montana-Dakota customers. Upon implementation of final rates in this case, Great Plains customers will be served under Montana-Dakota's tariffs but will continue to receive a Great Plains bill up to one year after the implementation of final rates in this case. At that time customers will begin receiving their natural gas bills under a Montana-Dakota invoice.

The Company proposes a second phase of rate changes also after a one year period at which time Great Plains customers will begin to be billed under a Montana-Dakota invoice. The completion of common rates between Great Plains and Montana-Dakota customers will take place in a future rate case in order to avoid significant changes in the rate structure.

Q. Is the Company seeking interim rate relief in this proceeding?

A. Yes. Interim rate relief is being sought in this case consistent with North Dakota Century Code 49-05-06. The amount of interim relief sought is $6,893,176 or 6.0 percent and consists of the Company’s projected 2021 revenue requirement adjusted to reflect the rate of return of 9.40 percent authorized in Case Nos. PU-17-295 and PU-17-490, exclusion of rate case expense associated with this rate case and the pension regulatory asset in rate base as this was not a part of the last rate case. The Company recognizes that the current COVID-19 pandemic has impacted some of its customers. To minimize the impact to customers, the Company proposes the Commission grant a waiver of North Dakota Century Code 49-05-06, Section 2 that states “the commission shall order that the interim rate schedule take effect no later than sixty days after the initial filing date” and allow the Company to delay implementation of interim rates until January 1, 2021. The delay in the implementation of rates will reduce the impact on customers by approximately two months while, at the same time, allow the Company to begin to earn a reasonable rate of return. The interim request will be described in more detail by Ms. Vesey. The proposed interim rates are described by Ms. Bosch. The interim increase is necessary to provide the Company an opportunity to recover the costs of providing service to customers today.

Q. Will you please identify the witnesses who will testify on behalf of Montana-Dakota and Great Plains in this proceeding?

A. Yes. Following is a list of witnesses that will provide testimony and/or exhibits in support of the Company's application:

- Ms. Ann Bulkley, Senior Vice President of Concentric Energy Advisors, Inc. will testify regarding the appropriate cost of common equity for Montana-Dakota's and Great Plains' North Dakota gas operations.
- Mr. Patrick C. Darras, Vice President of Engineering and Operations Services for Montana-Dakota and Great Plains Natural Gas Co. will testify regarding the North Dakota gas distribution operations and the System Safety and Integrity Program.
- Ms. Tammy J. Nygard, Controller for the MDU Utilities Group, will testify regarding the overall cost of capital, capital structure, and overall debt costs.

- Mr. Matthew Shoemake, Regulatory Analyst for Montana-Dakota will testify regarding the volumes projected in this case.
- Mr. Travis R. Jacobson, Regulatory Affairs Director for Montana-Dakota will testify regarding an overview of the total revenue requirement and the interim revenue requirement necessary for North Dakota gas operations and the addition of the pension and post retirement benefits in rate base.
- Ms. Tara S. Vesey, Regulatory Affairs Manager for Montana-Dakota will testify regarding the total revenue requirement and the interim revenue requirement necessary for North Dakota gas operations.
- Mr. Ron Amen, Management Consulting Director for Black and Veatch Management Consulting, LLC will testify on the Company's embedded class cost of service study and proposed rate design.
- Ms. Stephanie Bosch, Regulatory Affairs Manager for Montana-Dakota will testify regarding proposed tariff changes and the proposed plan to transition Great Plains' customers to Montana-Dakota's gas tariff.

Q. Ms. Kivisto, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable as they are reflective of the total costs being incurred by the Company to provide safe and reliable natural gas service to its customers. The proposed rates will provide the Company the opportunity to earn a fair and reasonable return on its North Dakota natural gas operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-20___

Direct Testimony
of
Tammy J. Nygard

Q. Please state your name and business address.

A. My name is Tammy J. Nygard, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Controller for Montana-Dakota Utilities Co. (Montana-Dakota), Cascade Natural Gas Corporation (Cascade) and Intermountain Gas Company (Intermountain), subsidiaries of MDU Resources Group, Inc. as well as Great Plains Natural Gas Co. (Great Plains), a division of Montana-Dakota, collectively the MDU Utilities Group.

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

A. I am responsible for providing leadership and management of the accounting and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Montana-Dakota, Great Plains, Cascade, and Intermountain.

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

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and Computer Information Systems. I have over 18 years of experience in the utility industry. During my tenure with the MDU Utilities Group, I have held positions of increasing responsibility, including Financial Analyst for Montana-Dakota, Director of Accounting and Finance for Cascade, and now as MDU Utilities Group Controller.

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

A. I am responsible for presenting Statement E.

Q. Was this statement and the data contained therein prepared by you or under your supervision?

A. Yes, it was.

Q. Is it true to the best of your knowledge and belief?

A. Yes, it is.

Q. Would you please explain Statement E?

A. Statement E shows the utility capital structure of Montana-Dakota for the twelve months ended December 31, 2019 and the projected capital structure for 2020 and 2021. Statement E includes the associated costs of debt and common equity. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 7.304 percent. The basis for the requested 10.20 percent return on common equity contained within the overall requested rate of return is supported by the testimony of Ms. Ann Bulkley.

Statement E summarizes the utility capital structure and the related utility costs of capital at December 31, 2019 and the projected capital structure and the related utility costs of capital for 2020 and 2021. As shown on page 1, the components of the 2021 projected overall annual rate of return, which are used by Ms. Vesey to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	1.999%
Short Term Debt	0.174%
Equity	5.131%
Required Rate of Return	7.304%

Q. How does the Company finance its natural gas utility operations and determine the amount of common equity and debt to be included in its capital structure?

A. As a regulated public utility, the Company has a duty and obligation to provide safe and reliable service to its customers across its service territory while prudently balancing cost and risk. In order to fulfill its service obligations, the Company has made significant capital expenditures for new plant investment throughout its service territory, especially in mains and services, including System Safety and Integrity Projects (SSIP). These new investments also have associated operating and maintenance costs. Through its financial planning process, the Company determines the amounts of necessary financing required to support these activities. Montana-Dakota finances its operations with a target of 50 percent common equity. Capital expenditure investments are financed through a mix of internally generated funds, the utilization of the Company's short-term credit line and the issuance of additional debt and common equity financing as required to maintain targeted capital ratios and finance the combined utility operations.

The Company issued $100 million senior notes in both October and November 2019, for a total of $200 million. The Company does not anticipate long term debt issuances in 2020 or 2021.

Q. What does Statement E, Schedule E-1 show?

A. Page 1 is a summary showing the Company's long-term debt at December 31, 2019 and associated cost of debt, and it shows the projected long-term debt and associated costs for 2020 and 2021. Page 2 shows the cost and the debt balance by issue at December 31, 2019. Page 3 shows the projected cost and the debt balance by issue at December 31, 2020 and page 4 shows the projected cost and the debt balance by issue at December 31, 2021.

Q. How did you derive the projected cost of debt for 2020 and 2021?

A. The projected cost of debt for 2020 and 2021 is based upon the yield-to-maturity of each debt issue outstanding.

Q. Would you please describe Statement E, Schedule E-2?

A. Schedule E-2 presents the twelve-month average short-term debt balance for 2019 and projected 2020 and 2021 as well as the average cost of short-term debt. A twelve-month average of short-term debt is used in the cost of capital calculation to reflect the seasonality in the short-term debt balance. Short-term debt is historically at or near its peak in December and the twelve-month average calculation is more reflective of the borrowing level than a year-end balance.

Q. What does Statement E, Schedule E-3 show?

A. The schedule presents the common equity balance at December 31, 2019 and the projected balance for December 31, 2020 and December 31, 2021 reflecting the projected activity.

Q. Would you please describe Statement E, Schedule E-4 and explain the amortization method utilized?

A. Schedule E-4 reflects the annual amortization of the costs associated with the redemption of long-term debt. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues. The Company uses the same calculation for accounting purposes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-20___

PREPARED DIRECT TESTIMONY OF

ANN E. BULKLEY

Q1. Please state your name and business address.

A1. My name is Ann E. Bulkley. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q2. What is your position with Concentric Energy Advisors, Inc. ("Concentric")?

A2. I am employed by Concentric as a Senior Vice President.

Q3. On whose behalf are you submitting this Direct Testimony?

A3. I am submitting this Direct Testimony before the North Dakota Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. My testimony addresses the regulated natural gas operations of Montana-Dakota Utilities Co. within North Dakota ("Montana-Dakota" or the "Company").

Q4. Please describe your education and experience.

A4. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 20 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a summary of testimony that I have filed in other proceedings as Exhibit No.___(AEB-2), Schedule 1.

Q5. Please describe Concentric's activities in energy and utility engagements.

A5. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. Our financial advisory activities include buy and sell-side merger, acquisition, and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

Q6. Have you testified before any regulatory authorities?

A6. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit No.___(AEB-2), Schedule 1.

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q7. Please describe the purpose of your Direct Testimony.

A7. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the appropriate Return on Equity ("ROE")[1] for

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[1] Throughout my direct testimony, I interchangeably use the terms "ROE" and "cost of equity".

Montana-Dakota's natural gas operations in North Dakota to be used for ratemaking purposes. I also address the appropriateness of the Company's proposed capital structure. My analyses and recommendations are supported by the data presented in Exhibit No.___(AEB-2), Schedules 2 through 10, which were prepared by me or under my direction.

Q8. Please provide a brief overview of the analyses that led to your ROE recommendation.

A8. As discussed in more detail in Section VI, I applied the Constant Growth form of a Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. My recommendation also takes into consideration: (1) the Company's small size; (2) flotation costs; (3) the Company's capital expenditure requirements; (4) the regulatory environment in which the Company operates; and (5) the Company's adjustment mechanisms. Finally, I considered the Company's proposed capital structure as compared to the capital structures of the proxy companies.[2] While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results.

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[2] The selection and purpose of developing a group of comparable companies will be discussed in detail in Section V of my Direct Testimony.

Q9. How is the remainder of your Direct Testimony organized?

A9. Section II provides a summary of my analyses and conclusions. Section III reviews the regulatory guidelines pertinent to the development of the cost of capital. Section IV discusses current and projected capital market conditions and the effect of those conditions on Montana-Dakota's cost of equity in North Dakota. Section V explains my selection of a proxy group of natural gas utilities. Section VI describes my analyses and the analytical basis for the recommendation of the appropriate ROE for Montana-Dakota. Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case. Section VIII assesses the Company's proposed capital structure as compared to the proxy group. Section IX presents my conclusions and recommendations for the market cost of equity.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q10. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A10. In developing my recommended ROE for Montana-Dakota, I considered the following:

- The *Hope* and *Bluefield* decisions[3] that established the standards for determining a fair and reasonable allowed ROE, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.

[3] Federal Power Commission v. *Hope Natural Gas Co.,* 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co*., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

- The effect of current and projected capital market conditions on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity.
- The Company's regulatory, business, and financial risks relative to the proxy group of comparable companies, and the implications of those risks.

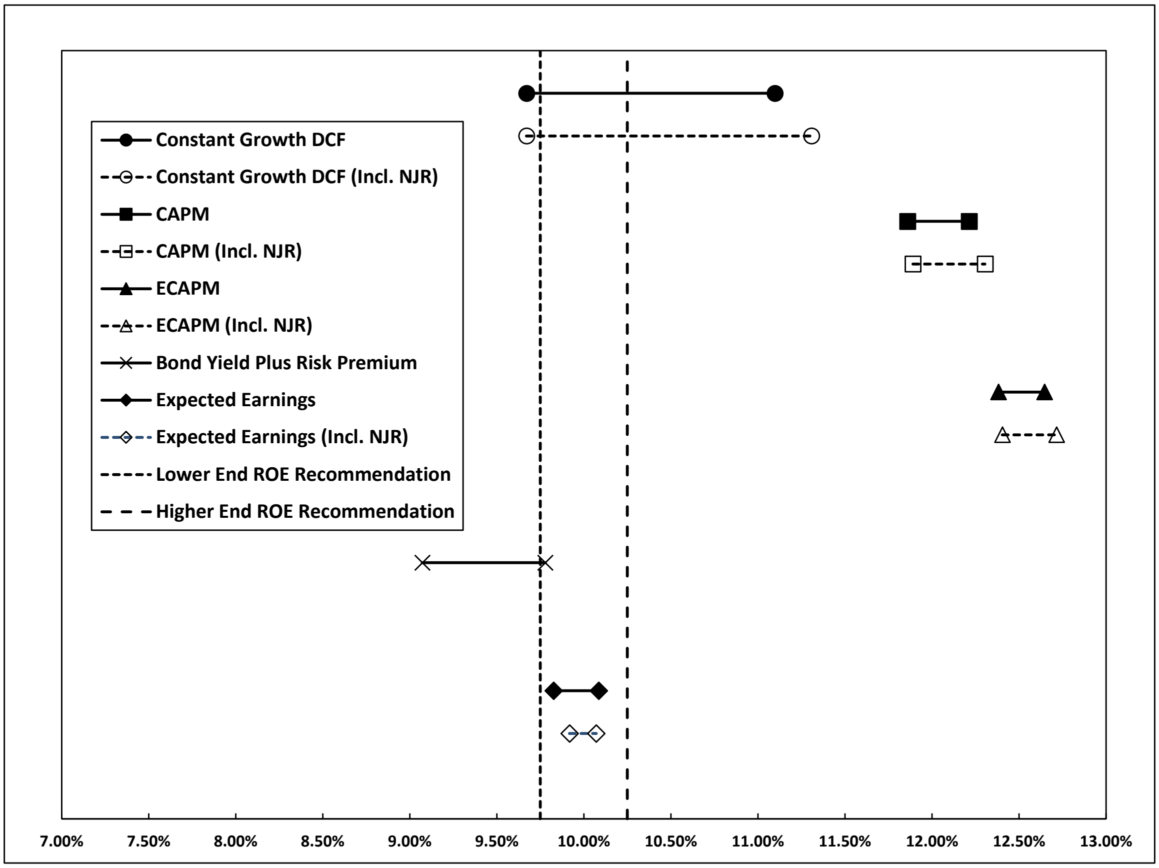
Q11. Please explain how you considered those factors.

A11. I relied on several analytical approaches to estimate Montana-Dakota's cost of equity based on a proxy group of publicly traded companies. As shown in Figure 1, those ROE estimation models produce a wide range of results. My conclusion about where within that range of results Montana-Dakota's cost of equity falls is based on the Company's business and financial risk relative to the proxy group. Although the companies in my proxy group are generally comparable to Montana-Dakota, each company is unique, and no two companies have the exact business and financial risk profiles. Accordingly, I selected a proxy group with similar, but not the same risk profiles; and I adjusted the results of my analysis either upwards or downwards within the reasonable range of results to account for any residual differences in risk.

Q12. Please summarize the results of the ROE estimation models that you considered to establish the range of ROEs for Montana-Dakota.

A12. Figure 1 summarizes the range of results produced by the Constant Growth DCF, CAPM, ECAPM, Bond Yield Plus Risk Premium, and Expected Earnings analyses.

Figure 1: Summary of Cost of Equity Analytical Results [4,5]



As shown in Figure 1 (and in Exhibit No.___(AEB-2), Schedule 2), the range of results produced by the ROE estimation models is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results is wide in order to appropriately consider the factors that have resulted in the diverging range of results.

Based on current market conditions, my ROE recommendation considers the results of a DCF model, forward looking CAPM and ECAPM analyses, a Bond Yield Plus

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4 The analytical results reflect the results of the Constant Growth DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7.00 percent.

5 Results displayed are for the proxy group excluding and including NJR.

Risk Premium analysis, and an Expected Earnings analysis. I also consider company-specific risk factors and current and prospective capital market conditions.

Q13. What is your recommended ROE for Montana-Dakota?

A13. Considering the analytical results presented in Figure 1, as well as the level of regulatory, business, and financial risk faced by Montana-Dakota's natural gas operations in North Dakota relative to the proxy group, I believe a range from 9.75 to 10.25 percent is reasonable**.** This recommendation reflects the range of results for the proxy group companies, the relative risk of Montana-Dakota's natural gas operations in North Dakota as compared to the proxy group, and current capital market conditions. Within that range, a return of 10.20 percent is reasonable.

Q14. Please summarize the analysis you conducted in determining that Montana-Dakota's requested capital structure is reasonable and appropriate.

A14. Based on the analysis presented in Section VIII of my testimony, I conclude that Montana-Dakota's proposed 50.306 percent common equity is reasonable. To determine if Montana-Dakota's requested capital structure was reasonable, I reviewed the capital structures of the utility subsidiaries of the proxy companies. As shown in Exhibit No.___(AEB-2), Schedule 10, the results of that analysis demonstrate that the average equity ratios for the proxy group range from 48.52 percent to 63.55 percent, with an average of 55.73 percent. Comparing the proposed equity ratio to the proxy group demonstrates that the Company's requested equity ratio is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies. Further, the Company's proposed equity ratio is reasonable considering that federal tax reform legislation has had a negative effect on the cash flows and credit metrics of regulated utilities.

III. REGULATORY GUIDELINES

Q15. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A15. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[6]

Q16. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A16. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable natural gas service while maintaining its financial integrity. To the extent the Company is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

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[6] *Hope,* 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

Q17. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A17. Yes. Utilities compete directly for capital with other investments of similar risk, which include other natural gas and electric utilities. Therefore, the ROE awarded to a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE significantly below authorized ROEs for other natural gas and electric utilities can inhibit the utility's ability to attract capital for investment in North Dakota.

While Montana-Dakota is committed to investing the required capital to provide safe and reliable service, because Montana-Dakota is a subsidiary of MDU Resources, the Company competes with the other MDU Resources subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for MDU Resources to consider the authorized ROE of each of its subsidiaries.

Q18. What are your conclusions regarding regulatory guidelines?

A18. The ratemaking process is premised on the principle that a utility must have the opportunity to recover the return of, and the market-required return on, its invested capital. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions; doing so balances the long-term interests of the utility and its ratepayers.

The financial community carefully monitors the current and expected financial condition of utility companies, and the regulatory framework in which they operate. In that respect, the regulatory framework is one of the most important factors in both debt and equity investors' assessments of risk. The Commission's order in this proceeding, therefore, should establish rates that provide the Company with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms under a variety of economic and financial market conditions; (2) sufficient to ensure good financial management and firm integrity; and (3) commensurate with returns on investments in enterprises with similar risk. To the extent Montana-Dakota is authorized the opportunity to earn its market-based cost of capital, the proper balance is achieved between customers' and shareholders' interests.

IV. CAPITAL MARKET CONDITIONS

Q19. Why is it important to analyze capital market conditions?

A19. The ROE estimation models rely on market data that are either specific to the proxy group, in the case of the DCF model, or the expectations of market risk, in the case of the CAPM. The results of ROE estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the practitioner uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates in the ROE estimation models to estimate the required return for the subject company.

As discussed in the remainder of this section, current market conditions affect the results of ROE estimation models. As a result, it is important to consider the effect of these conditions on the ROE estimation models when determining the appropriate range and recommended ROE to be determined for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q20. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

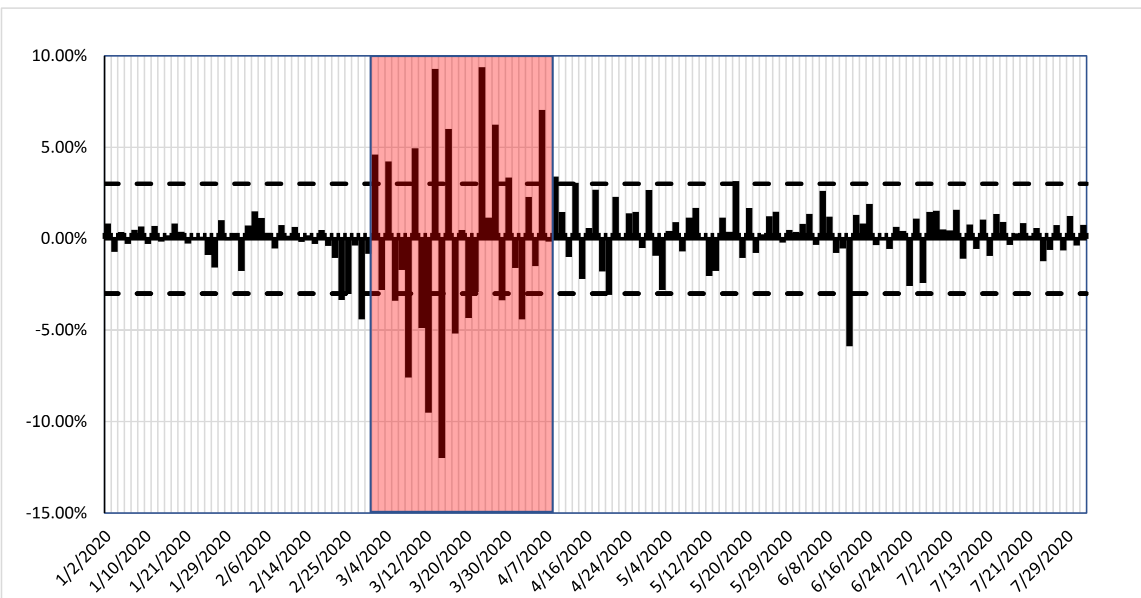
A20. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) the current market volatility has created a short-term aberration in the market which must be carefully considered when selecting the inputs for the ROE estimation models; 2) utility stock valuations, which are inversely related to dividend yields, are currently unsustainably high given investors' demand for defensive sectors during the short-term market dislocation; and (3) the effect of recent Federal tax reform on utility cash flows. In this section, I discuss each of these factors and how it affects the models used to estimate the cost of equity for regulated utilities.

A. Current Market Conditions

Q21. Please summarize current market conditions.

A21. In 2020, market conditions have been extremely volatile. In January and early February 2020, major market indices were generally increasing, many reaching new threshold levels. By mid-February, as the global health pandemic became more apparent, market conditions became increasingly more volatile. In mid-February, utility stock prices reached an all-time high, followed by a significant decline in the overall market and utility stocks. Market conditions in March 2020 were more volatile than the last half of February. As shown in Figure 2 below, the S&P 500 Index swung more than 3 percent in 16 of the 22 trading days in the month of March.

Figure 2: S&P 500 Index – Daily Price Change – January-July 2020[7]



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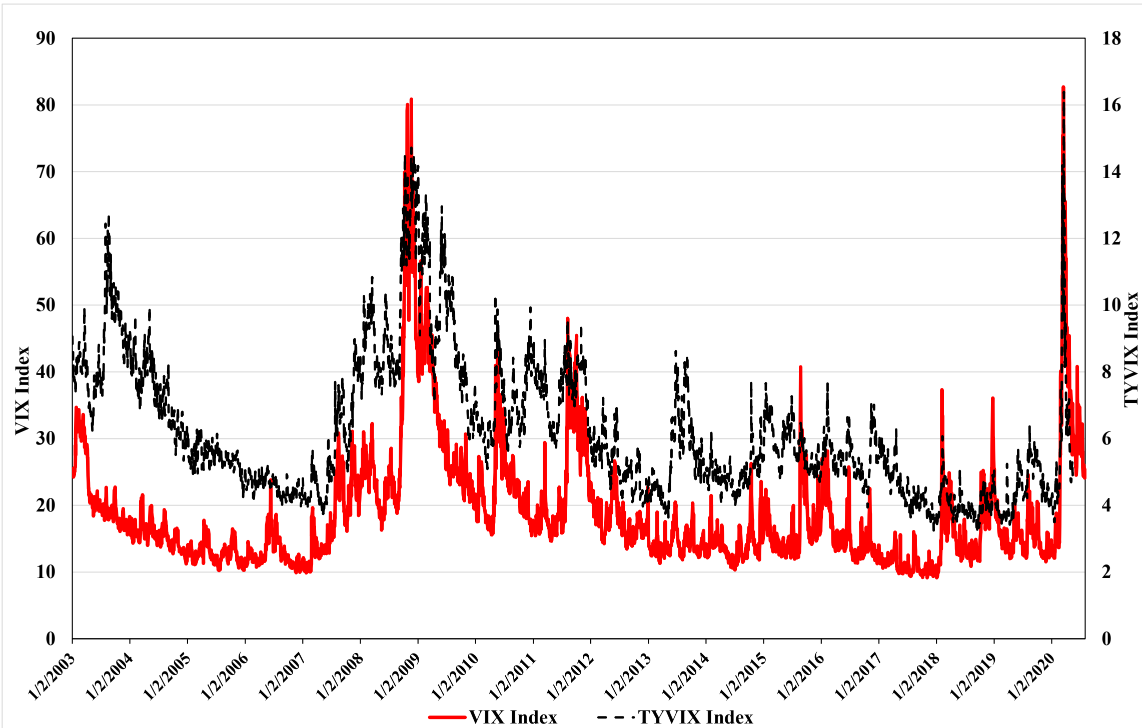
[7] Source: S&P Global Market Intelligence.

Q22. Have you reviewed any other indicators that measure volatility in the financial markets?

A22. Yes. I reviewed two other measures of volatility in financial markets: 1) the CBOE Volatility Index ("VIX"), and 2) the U.S. Treasury Note Volatility Index ("TYVIX"). The VIX measures investors' expectation of volatility in the S&P 500 over the next 30 days. The TYVIX, also published by CBOE, measures investors' expectation of volatility in the 10-year Treasury Bond over the next 30 days. As shown in Figure 3, the VIX and TYVIX have recently reached levels not seen since the Great Recession of 2008/09. For example, the VIX was 82.69 on March 16, 2020. The VIX has not reached 80.00 since November of 2008; however, it is important to note that the highest level reached during the Great Recession of 2008/09 was 80.86. Similarly, the TYVIX was 16.39 on March 19, 2020. Since at least January 2003, the TYVIX has never exceeded 15.00 including during the Great Recession of 2008/09. While the VIX and the TYVIX have declined since the March peaks, in response to the efforts of the Federal Reserve, these indicators show that COVID-19 has caused an increase in the level of uncertainty and volatility in the market even greater than during the Great Recession of 2008/09.

Furthermore, as shown in Figure 3, while the VIX has declined between April and July, this measure of volatility still remains well above levels seen prior to COVID-19 in January and February 2020. It is important to view the declines in the VIX in the context of the unprecedented response by the Federal Reserve and Congress. As discussed in more detail below, the Federal Reserve's corporate bond buying programs are providing liquidity to bond markets and therefore reducing some of the uncertainty that was driving the volatility seen in March. However, there is still much uncertainty regarding the near-term effect of COVID-19 on the economy and the financial markets, which is why the VIX is still above its long-term average.

Figure 3: CBOE VIX and TYVIX – January 2003 to July 2020[8]



Q23. Have rating agencies commented on the effects of current market conditions on regulated utilities?

A23. Yes. Standard & Poor's ("S&P") recently downgraded the outlook on the entire North American utilities sector indicating that 25 percent of the industry was previously on a negative outlook or CreditWatch with negative implications and that S&P expected that COVID-19 would create incremental pressure and that a recession would lead to an increasing number of downgrades and negative

[8] Source: Bloomberg Professional. The CBOE did not renew the contract for the TYVIX; therefore, the data for this index is not available after May 15, 2020.

outlooks.[9] In May, S&P also noted that many utilities already faced ratings pressure due to several factors including the adverse effects of tax reform of 2019 and historically high capital spending. S&P noted that, as a result of these types of factors, there is an unusually high number of negative outlooks for utilities.[10]

Q24. What steps have the Fed and Congress taken to stabilize financial markets and support the economy?

A24. In response to effects of COVID-19, the Federal Reserve met on March 15, 2020 and acknowledged that the spread of COVID-19 posed increased risks to economic activity in the U.S. In response, the Federal Reserve reduced the federal funds rate by 100 basis points, resulting in a target range of 0.00 percent to 0.25 percent.[11] This was the second unscheduled meeting in March 2020, with the first occurring on March 3rd, when the Federal Reserve reduced the federal funds rate by 50 basis points. In addition to the reduction in the federal funds rate, the Federal Reserve also announced plans to increase its holdings of both Treasury and mortgage-backed securities.[12] On March 23, 2020, the Federal Reserve began expansive programs to support credit to large employers; the Primary Market Corporate Credit Facility ("PMCCF") to provide liquidity for new issuances of corporate bonds, and the Secondary Market Corporate Credit Facility ("SMCCF") to provide liquidity for outstanding corporate debt issuances. These programs initially targeted

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9 Standard & Poor's Ratings Direct, COVID-19: The Outlook for North American Regulated Utilities Turns Negative, April 2, 2020.

10 Standard & Poor's Ratings Direct: North American Regulated Utilities Face Tough Financial Policy tradeoffs To Avoid Ratings Pressure Amid The COVID-19 Pandemic, May 11, 2020, p. 3.

11 FOMC, Federal Reserve Board Press Release, March 15, 2020, at 1.

12 *Id.,* at 2.

investment grade corporations, but in April 2020 were expanded to include corporations that were rated investment grade as of March 22, 2020. The PMCF and SCCF programs were initially funded at $75 billion, but the combined size of these programs, including the addition of below investment grade corporate debt is proposed to be up to $750 billion.[13] Further, the Federal Reserve supported the flow of credit to consumers and businesses through the Term Asset-Backed Securities Loan Facility ("TALF").[14]

In addition to the Federal Reserve, the U.S. Congress also passed fiscal stimulus programs. On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security ("CARES") Act was signed into law. The CARES Act is a large fiscal stimulus package aimed at mitigating the economic effects of the coronavirus. While these expansive programs have provided for greater price stability, as shown in Figure 3, the VIX remains well above long-term historical normal levels.

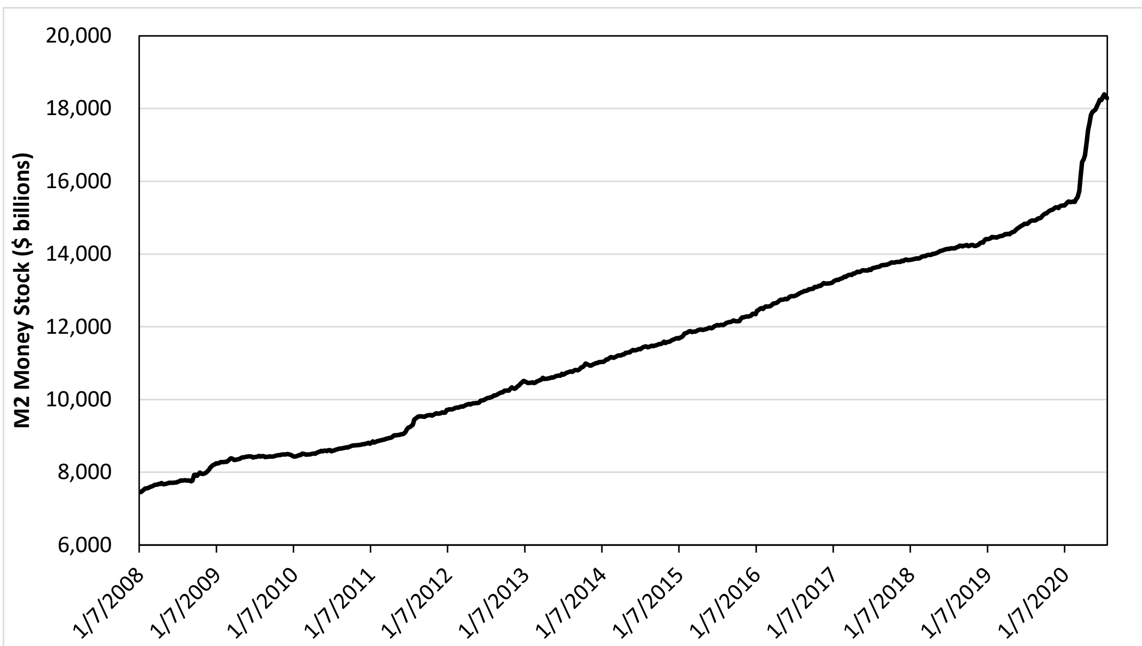
Q25. How do the Federal Reserve's recently announced programs affect the economy and financial markets?

A25. The programs allow the Federal Reserve to purchase, from banks, government bonds and corporate bonds. The banks then receive cash from the Federal Reserve, which results in an expansion of the money supply. The increase in the money supply keeps interest rates low and increases the ability of banks to lend to consumers and businesses. This is very important given current market

[13] FOMC Term Sheet, Primary and Secondary Corporate Credit Facilities, April 9, 2020.
[14] Federal Reserve Board Press Release, "Federal Reserve announces extensive new measures to support the economy", March 23, 2020.

circumstances because it allows companies to continue to get access to the liquidity needed to offset the negative effects of COVID-19 on business operations. As shown in Figure 4 below, the programs enacted by the Federal Reserve have resulted in an unprecedented expansion of the money supply, as measured by M2[15], in recent months—much greater than the increase seen following the Federal Reserve's response to the Great Recession of 2008/2009.

Figure 4: M2 Money Stock – January 2008 – July 27, 2020[16]



Q26. How has the market responded to the unprecedented intervention by the Federal Reserve?

A26. The uncertainty surrounding the spread of COVID-19 resulted in a flight to quality, as investors purchased safer assets such as U.S. Treasuries due to increased fears

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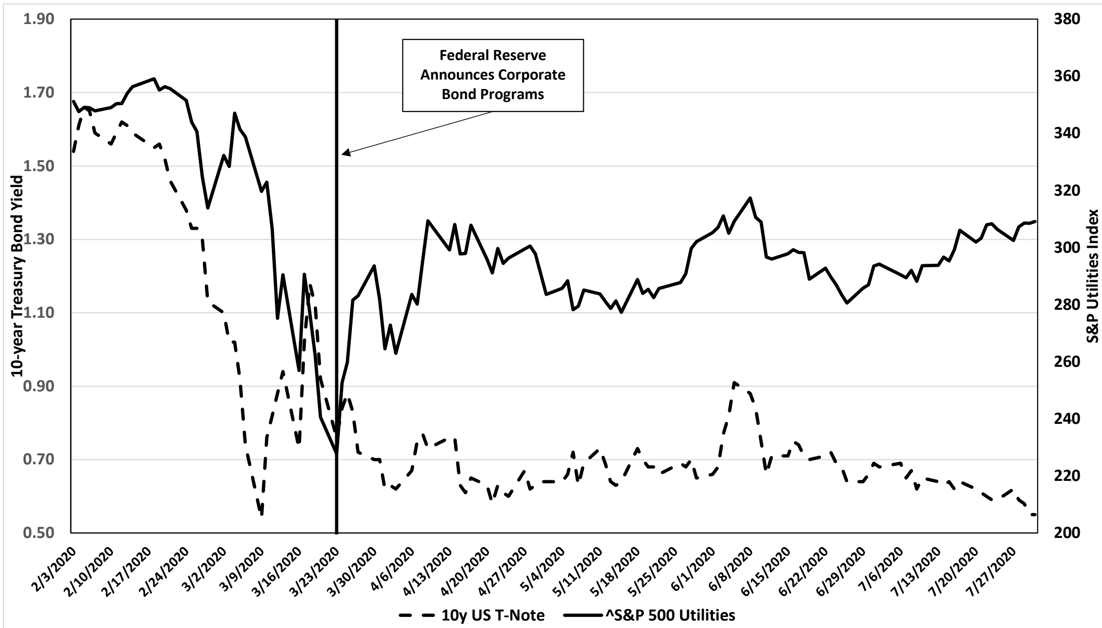
15 M2 is defined by the Federal Reserve as follows: M2 includes a broader set of financial assets held principally by households. M2 consists of M1 plus: (1) savings deposits (which include money market deposit accounts, or MMDAs); (2) small-denomination time deposits (time deposits in amounts of less than $100,000); and (3) balances in retail money market mutual funds (MMMFs).

16 Board of Governors of the Federal Reserve System (US), M2 Money Stock [M2], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/M2, August 10, 2020.

of a recession. This has been increasingly evident over the past few months as investors responded to news of the number of COVID-19 cases outside of China and the economic effects of the policies enacted to contain COVID-19. However, as discussed above, in late March, the Federal Reserve began expansive programs with the purpose of maintaining access to capital markets for corporate borrowers. These unprecedented programs resulted in lower borrowing costs for corporate firms and thus continued access to the capital needed to offset the economic effects of COVID-19. As a result, interest rates have remained low and stability has been restored in the corporate bond market. For investors, this led to allocating more funds to equities. As shown in Figure 5, while the yield on the 10-year Treasury Bond has remained relatively stable and in the range of 0.55 percent to 0.91 percent between March 23, 2019 and July 31, 2019, the S&P Utilities Index increased drastically following the Federal Reserve's announcement on March 23, 2020. Therefore, the polices of the Federal Reserve, while resulting in stability in the bond markets, have resulted in inflated equity prices as investors search for returns in the current low interest rate environment.

Figure 5: 10-year U.S. Treasury Bond Yield and S&P Utilities Index



Q27. What are your conclusions regarding the recent market volatility and its effect on the cost of equity for Montana-Dakota?

A27. Given the uncertainty and volatility that has characterized capital markets in 2020, it is reasonable that equity investors would now require a higher return on equity to compensate them for the additional risk associated with owning common stock under these market conditions. Therefore, ROE estimation models that rely on recent market data must be interpreted with caution to ensure the data is reflective of market conditions over the near term. For example, the Constant Growth DCF model relies on the average share prices for the proxy companies, which have been extremely volatile in the last several months; those prices are likely currently influenced by the policies of the Federal Reserve and are not likely representative of what should be expected during the period that Montana-Dakota's rates will be in effect. This highlights two key factors that must be considered when determining the ROE for Montana-Dakota: (1) current and prospective market conditions should be considered when determining where within the range of results Montana-Dakota's ROE should be set, and (2) where possible, in each of the models, it is necessary to consider projected market data which reflect economists' expectations for the market conditions that will prevail during the period that Montana-Dakota's rates will be in effect.

B. The Effect of Market Conditions on Valuations

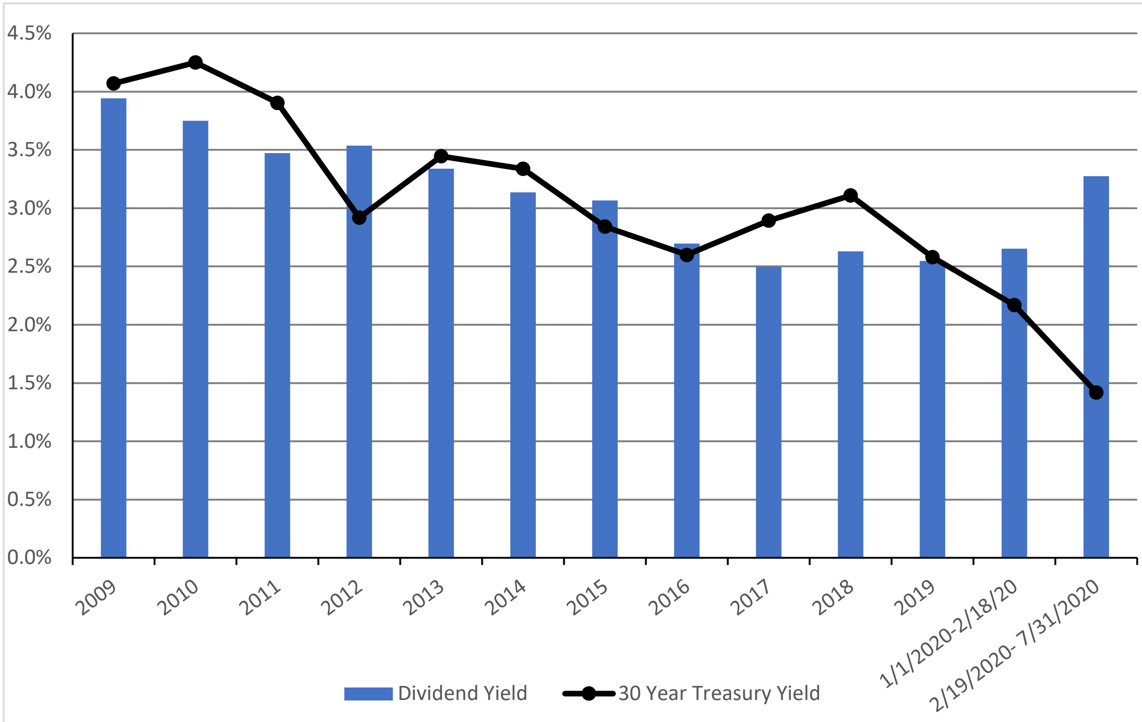
Q28. Please provide a brief summary of how the Federal Reserve's monetary policy affected capital markets following the Great Recession of 2008/09.

A28. Extraordinary and persistent federal intervention in capital markets artificially lowered government bond yields after the Great Recession of 2008/09, as the Federal Reserve Open Market Committee ("FOMC") used monetary policy (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage-backed securities) to stimulate the U.S. economy. As a result of very low or zero returns on short-term government bonds, yield-seeking investors were forced into higher risk instruments, bidding up prices and reducing yields on those investments. As investors moved along the risk spectrum in search of yields meeting their return requirements, demand increased for dividend-paying equities, such as utility stocks. As a result, valuations of utilities were at historically high levels just prior to the spread of COVID-19 to the U.S.

Q29. How has the economic impact of COVID-19 affected the valuations and dividend yields of utility shares?

A29. The Federal Reserve's accommodative monetary policy following the Great Recession of 2008/09 caused investors to seek alternatives to the historically low interest rates available on Treasury bonds, which resulted in the share prices for many common stocks, especially dividend-paying stocks such as utilities, being driven higher. Consequently, dividend yields (which are computed by dividing the dividend payment by the stock price) decreased to levels well below the historical average. As shown in Figure 6, over the period from 2009 through February 18, 2020 (i.e., the peak of the market prior to the recent decline resulting from the effects of COVID-19), Treasury bond yields and natural gas utility dividend yields had declined. While investors have responded to the economic effects of COVID-19, resulting heightened volatility and a recent decline in the market, it is important to highlight the relative performance of natural gas utilities during this time period. As shown in Figure 6, while the stock prices of natural gas utilities have declined, which has resulted in an increase in dividend yields, the average dividend yield for natural gas utilities over the period of February 19, 2020 through July 31, 2020 was 3.28 percent, which is still unreasonably low when compared to historical dividend yields.

Figure 6: Dividend Yields for Natural Gas Utility Stocks[17]



Q30. Have equity analysts commented on the valuations of utility stocks?

A30. Yes, they have. Despite the correction that occurred in March 2020, several equity analysts continue to believe that utility stock valuations are very high relative to historical levels. In a recent electric utilities industry report**,** Value Line noted the following:

> Utilities are usually seen as a safe haven when the markets are in turmoil. Most of these stocks have declined far less than the broader market averages, but have been much more volatile than their high Price Stability Indexes suggest. Even a Safety rank of 1 (Highest) does not necessarily mean that a sharp decline cannot occur. Additionally, there has been a wide variance in the performance of these equities. The stock of Xcel Energy has advanced modestly in price this year, but the stock of Edison International has fallen more than 20% in price. The average dividend yield of stocks in this industry has risen to 3.55% after having fallen below 3% before the market tumbled in late February. Because the broader market has declined far more than the Electric Utility Industry, the median yield

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[17] Source: Bloomberg Professional. Figure 6 includes 2020 data through July 31, 2020.

> of dividend-paying stocks in The Value Line Investment Survey is not considerably lower than the median of the equities in this group.[18]

While the reference above is to the electric utilities segment, the stock price behavior is consistent with what has been experienced by natural gas utilities. This is further supported in Fidelity's 2020 Q3 sector scorecard, wherein Fidelity expects that utilities will underperform relative to the broader market, notes the sector's high valuations, and thus classifies the utility sector as underweight.[19] Similarly, Charles Schwab, which recently downgraded the utility sector to underperform, noted that:

> However, amid the drop in stocks in February and March, the historically low-equity-beta Utilities sector simply didn't play its traditional relative safe-haven role. The sharp drop in interest rates would normally be expected to provide relative support to this sector, which relies on high levels of debt and tends to pay relatively high dividends—often an attraction for investors when yields on fixed income investments are low. However, there were unique circumstances that outweighed these historical relationships.
>
> For one thing, because some investors had already been reaching for yield before the crisis began, the high-dividend-paying Utilities sector had been bid up to record-high valuation levels. Even underperformance year-to-date hasn't fully reversed those relatively high valuations, so we're not confident the sector will return to its defensive roots if markets sell off again.
>
> Additionally, with improving prospects for economic growth, longer-term yields may nudge higher, which further reduces the sector's attractiveness. The earnings outlook has remained stable (when not including a major divestiture in the sector), but the relative fundamentals score took a step back recently as other beaten down sectors have seen some recovery in earnings expectations.

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[18] Value Line Investment Survey, Electric Utility (West) Industry, April 24, 2020, at 2214.

[19] Chisholm, Denise. "Q3 2020 Sector Scorecard: Technology leads Fidelity's latest sector scorecard," Fidelity, July 27, 2020.

> And the sector's short-term relative performance has lagged, despite a recent increase in volatility and drop in rates amid a rise in COVID-19 cases. Bottom line, we are maintaining an underperform rating on Utilities.[20]

If economic conditions improve and interest rates increase, bonds become a substitute for utility stocks, which results in an increase in dividend yields. This change in market conditions, which is expected over the long term, implies that the ROE calculated using historical market data in the DCF model may understate the forward-looking cost of equity.

Q31. What is the effect of high valuations of utility stocks on the DCF model?

A31. High valuations have the effect of depressing the dividend yields, which results in overall lower estimates of the cost of equity from the DCF model. Currently, the relatively high valuations and relatively low dividend yields imply that the ROE calculated using historical market data in the DCF model may understate the forward-looking cost of equity.

Q32. How do the valuations of public utilities compare to the historical average?

A32. Figure 7 summarizes the average historical and projected Price-to-Earnings ("P/E") ratios for the proxy companies calculated using data from Bloomberg Professional and Value Line. As shown in Figure 7, the P/E ratios for the proxy companies have declined in 2020 as investors have rotated from utilities to Treasury Bonds due to the economic effects of COVID-19. Nonetheless, as of July 31, 2020, the P/E ratios are still well above historical averages.

[20] Charles Schwab, Utilities Sector Rating: Underperform, July 16, 2020.

As shown in Figure 7, Value Line is projecting that P/E ratios will continue to decline through 2023. All else equal, if P/E ratios for the proxy companies decline further, as Value Line projects, the ROE results from the DCF model would be higher.

Therefore, the DCF model using historical market data is likely understating the forward-looking cost of equity for the proxy group companies.

Figure 7: Average Historical Proxy Group P/E Ratios[21]

Q33. Have you reviewed any other market indicators that compare the current valuation of utilities to the historical average?

A33. Yes, I have. To further assess how the currently low interest rate environment has affected the valuations of the companies in my proxy group, I reviewed the

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[21] Bloomberg Professional historical data through July 31, 2020; Value Line Investment Survey Reports dated July 31, 2020.

price/earnings to growth ("PEG") ratio for the S&P Utilities Index. The PEG ratio is commonly used by investors to determine if a company is considered over- or under-valued. The ratio compares the P/E ratio of a company to the expected growth rate of future earnings. This allows investors to compare companies with similar P/E ratios but different earnings growth projections. If two companies have a P/E ratio of 20, but Company A is growing at a rate of 6 percent and Company B is growing at a rate of 15 percent, then on a relative valuation basis Company B is the better investment.

As shown in a report published by Yardeni Research, Inc., the PEG ratio for the S&P Utilities Index is significantly higher than it has historically been because of the accommodative monetary policy pursued by the Federal Reserve following the Great Recession of 2008/09.[22] While the PEG ratio has slightly declined recently as investors have rotated out of defensive sectors and into Treasury Bonds due to the short-term economic effect of COVID-19, the PEG ratio for the S&P Utilities Index is still above the historical average. In general, stocks with lower long-term PEG ratios are considered better values. As the PEG ratio increases above the long-term historical average, as has been the case with the S&P Utilities Index, then the stocks are considered relatively over-valued unless the growth rate increases to support the higher valuation. As of July 30, 2020, the PEG ratio for the S&P Utilities Index is close to 3.9, which indicates that many of the stocks contained in the index are currently trading at levels well above the historical average. This

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[22] Yardeni Research, Inc. "S&P 500 Industry Briefing: Utilities." June 4, 2020, p. 5.

analysis supports the P/E ratio projections produced by Value Line, which, as noted above, show a decline over the near term.

C. Effect of Tax Reform on the ROE and Capital Structure

Q34. Are there other factors that should be considered in determining the cost of equity for Montana-Dakota?

A34. Yes, there are. The effect of the Tax Cuts and Jobs Act of 2017 ("TCJA") should also be considered in the determination of the cost of equity. It is also relevant to setting the equity ratio in the capital structure, which I address in Section VIII of my testimony. The credit rating agencies have commented on the effect of the TCJA on regulated utilities. In summary, the TCJA has reduced utility revenues due to the lower federal income taxes, the end of bonus depreciation, and the requirement to return excess Accumulated Deferred Income Taxes ("ADIT"). This change in revenue reduces Funds From Operations ("FFO") metrics across the sector and, absent regulatory mitigation strategies, has led to weaker credit metrics and negative ratings actions for some utilities.[23]

Q35. Have credit or equity analysts commented on the effect of the TCJA on utilities?

A35. Yes, they have. Each of the credit rating agencies has indicated that the TCJA is having an overall negative credit impact on regulated operating companies of

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[23] FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector," January 24, 2018.

utilities and their holding companies due to the reduction in cash flow that results from the change in the federal tax rate and the loss of bonus depreciation. [24,25]

Q36. How have rating agencies responded to the increased risk for utilities resulting from the TCJA?

A36. As noted previously, S&P recognizes the financial risk and notes that the percentage of the sector that have negative credit outlooks is very high. Similar to S&P's view, Moody's downgraded the outlook for the entire regulated utility industry from Stable to Negative for the first time ever, citing ongoing concerns about the negative effect of the TCJA on cash flows of regulated utilities. Since mid-2018, Moody's has downgraded the credit ratings of several utilities based in part on the effects of tax reform on financial metrics. As shown in Figure 8, the downgrades have continued in recent months.

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[24] Standard & Poor's Ratings, "Industry Top Trends 2019, North America Regulated Utilities", November 8, 2018.

[25] FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.

Figure 8: Credit Rating Downgrades Resulting from TCJA

Utility	Rating Agency	Credit Rating before TCJA	Credit Rating after TCJA	Downgrade Date
Electric Transmission Texas	Moody’s	Baa1	Baa2	3/24/2020
New Jersey Natural Gas Company	Moody’s	Aa3	A1	3/18/2020
Consolidated Edison Company of New York	Moody’s	A3	Baa1	3/17/2020
Consolidated Edison, Inc.	Moody’s	Baa1	Baa2	3/17/2020
Washington Gas Light Company	Moody’s	A2	A3	1/30/2020
Public Service Co. of North Carolina, Inc.	Moody’s	A3	Baa1	1/30/2020
Wisconsin Power and Light Company	Moody’s	A2	A3	12/11/2019
Wisconsin Gas LLC	Moody’s	A2	A3	11/20/2019
Vectren Utility Holdings	Moody’s	A2	A3	10/25/2019
Southern Indiana Gas & Electric Company	Moody’s	A2	A3	10/25/2019
Indiana Gas Company	Moody’s	A2	A3	10/25/2019
El Paso Electric Company	Moody’s	Baa1	Baa2	9/17/2019
Questar Gas Company	Moody’s	A2	A3	8/15/2019
DTE Gas Company	Moody’s	A2	A3	7/22/2019
South Jersey Gas Company	Moody’s	A2	A3	7/17/2019
Central Hudson Gas & Electric	Moody’s	A2	A3	7/12/2019
Oklahoma Gas & Electric Company	Moody’s	A2	A3	5/31/2019
American Water Works	Moody’s	A3	Baa1	4/1/2019
Niagara Mohawk Power Corporation	Moody’s	A2	A3	3/29/2019
KeySpan Gas East Corporation (KEDLI)	Moody’s	A2	A3	3/29/2019
Xcel Energy	Moody’s	A3	Baa1	3/28/2019
ALLETE, Inc.	Moody’s	A3	Baa1	3/26/2019
Brooklyn Union Gas Company (KEDNY)	Moody’s	A2	A3	2/22/2019
Avista Corp.	Moody’s	Baa1	Baa2	12/30/2018
Consolidated Edison Company of New York	Moody's	A2	A3	10/30/2018
Consolidated Edison, Inc.	Moody's	A3	Baa1	10/30/2018
Orange and Rockland Utilities	Moody's	A3	Baa1	10/30/2018
Southwestern Public Service Company	Moody's	Baa1	Baa2	10/19/2018
Dominion Energy Gas Holdings	Moody's	A2	A3	9/20/2018
Piedmont Natural Gas Company, Inc.	Moody's	A2	A3	8/1/2018
WEC Energy Group, Inc.	Moody's	A3	Baa1	7/12/2018
Wisconsin Energy Capital	Moody’s	A3	Baa1	7/12/2018
Integrys Holdings Inc.	Moody's	A3	Baa1	7/12/2018
OGE Energy Corp.	Moody's	A3	Baa1	7/5/2018
Oklahoma Gas & Electric Company	Moody's	A1	A2	7/5/2018

Q37. Have other utility commissions recognized that the TCJA has had an adverse impact on utility cash flows?

A37. Yes, they have. The Oregon Public Utilities Commission ("Oregon PUC")[26], the Wyoming Public Service Commission ("Wyoming PSC")[27] and the Utah Public Service Commission ("Utah PSC")[28] have acknowledged the negative effect of the TCJA on the cash flow of utilities.

Q38. Have state regulatory commissions considered market events and the utility's ability to attract capital in determining the equity return?

A38. Yes, they have. In a recent rate case for Consumers Energy Company in Michigan, Case No. U-18322, the Michigan Public Service Commission ("Michigan PSC") Staff recommended a 9.80 percent ROE based on the results of the DCF, CAPM, and Risk Premium approaches, which was supported by the Administrative Law Judge ("ALJ").[29] However, in its Order issued on March 29, 2018, the Michigan PSC partly disagreed with the ALJ and Staff regarding expected market conditions and authorized a 10.00 percent ROE for Consumers Energy Company. The Michigan PSC noted that:

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[26] See *In the Matter of Avista Corporation, dba Avista Utilities, Application for Authorization to Issue 3,500,000 Shares of Common Stock*, Docket UF 4308, Order No. 19-067 (Feb. 23, 2019); *In the Matter of Avista Corporation, dba Avista Utilities, Application for Authorization to Issue and Sell $600,000,000 of Debt Securities*, UF 4313, Order No. 19-249 (July 30, 2019); *In the Matter of Portland General Electric Company, Request for Authority to Extend the Maturity of an Existing $500 Million Revolving Credit Agreement*, Docket UF 4272(3), Order No. 19-025 (Jan. 23, 2019).

[27] *In the Matter of Questar Gas Company dba Dominion Energy Wyoming's Application for Approval of Amended Stipulation Previously Approved in Docket No. 30010-150-GA-16*, Docket No. 30010-180-GA-18 (Record No. 15138) (Aug. 20, 2019).

[28] Report and Order, Docket No. 19-057-02, Dominion Energy Utah, February 25, 2020, at 6.

[29] Michigan Public Service Commission Order, Cause No. U-18322, Consumers Energy Company, March 29, 2018, at 37.

> [i]n setting the ROE at 10.00%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the Commission's belief that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner. The fact that other utilities have been able to access capital despite lower ROEs, as argued by many intervenors, is also a relevant consideration. It is also important to consider how extreme market reactions to singular events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.[30]

The Michigan PSC references "singular events" and the overall effect the events could have on the ability of a utility to access capital. Consistent with the Michigan PSC's views, it is important to consider a) that the TCJA has had a negative effect on the cash flows of utilities and b) the effects of the increase volatility associated with the uncertainty surrounding the economic effects of COVID-19.

Q39. What conclusions do you draw from your analysis of capital market conditions?

A39. The important conclusions regarding capital market conditions are:

- The assumptions used in the ROE estimation models have been affected by recent, historically atypical market conditions.
- Recent market conditions reflect short-term exogenous shocks that are not expected to persist over the long-term. These recent market conditions do not reflect the market conditions that are expected to be present when the rates for Montana-Dakota will be in effect.
- Recent market volatility demonstrates significant risk to equity, which increases the return investors expect in order to take on that incremental

[30] *Id.,* at 43.

risk. As a result, it is critical to consider the results of a variety of ROE estimation models, and to consider the results of the models using forward-looking assumptions to estimate the cost of equity for the proposed rate period.

- Credit rating agencies have demonstrated concern about the cash flow metrics of utilities, related to the negative effects of both current market conditions and the TCJA, which increases the risk of utilities for investors. Therefore, it is increasingly important to consider a rate of return and capital structure that support the Company's cash flow sufficiently to enable the Company to attract capital at reasonable terms during the period that rates will be in effect.

V. PROXY GROUP SELECTION

Q40. Why have you used a group of proxy companies to estimate the cost of equity for Montana-Dakota?

A40. In this proceeding, we are focused on estimating the cost of equity for a natural gas utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and because Montana-Dakota's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to Montana-Dakota in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if Montana-Dakota was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate ROE for Montana-Dakota.

Q41. Please provide a brief profile of Montana-Dakota.

A41. Montana-Dakota Utilities Co. is a wholly owned subsidiary of MDU Resources. It provides regulated retail natural gas and/or electric service to parts of Montana, North Dakota, South Dakota, and Wyoming. The Company's natural gas distribution operations in North Dakota serve approximately 113,239 residential, commercial and industrial customers.[31] As of December 31, 2019, the Company's net utility natural gas plant in North Dakota was approximately $196.1 million.[32] In addition, the Company had total natural gas sales in North Dakota in 2019 of approximately 27.50 million Dths, made up of 34.5 percent residential, 25.5 percent commercial and industrial, and 40.0 percent transportation.[33] For the Company's parent entity, MDU Resources, North Dakota accounted for 15.00 percent of its total natural gas distribution operating sales revenue in 2019, while Idaho (29.00 percent), Washington (28.00 percent), Montana (9.00 percent), Oregon (8.00 percent), South Dakota (6.00 percent), Minnesota (3.00 percent), and Wyoming (2.00 percent) accounted for the other 85.00 percent of its natural gas distribution operating sales revenue.[34] Montana-Dakota Utilities Co. currently has

[31] Montana-Dakota Utilities, 2019 Annual Report to the North Dakota Public Service Commission, IV. Miscellaneous, Line No. 6.
[32] Montana-Dakota Utilities, 2019 Annual Report to the North Dakota Public Service Commission, I. Intrastate Return on Equity, pp. 2 of 2, Line No. 3.
[33] Data provided by Montana-Dakota Utilities Co.
[34] MDU Resources Group, 2019 SEC Form 10-K, at 13.

an investment-grade long-term rating of A- (Outlook: Negative) from S&P and BBB+ (Outlook: Stable) from Fitch.[35] [36]

Q42. How did you select the companies included in your proxy group?

A42. I began with the group of ten companies that Value Line classifies as Natural Gas Distribution Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the Constant Growth DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- derive more than 70.00 percent of their total operating income from regulated operations;
- derive more than 60.00 percent of regulated operating income from gas distribution operations; and
- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q43. What is the composition of your proxy group?

A43. The screening criteria discussed above are shown in Exhibit No.___(AEB-2), Schedule 3 and resulted in a proxy group consisting of the companies shown in Figure 9 below.

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35 S&P Global Market Intelligence, March 30, 2020 report (verified as most recent rating as of Jun 17, 2020).

36 FitchRatings: Rating Action Commentary, Fitch Affirms Ratings of MDU, Montana-Dakota, Cascade and Centennial Energy; Outlooks Stable, January 3, 2020 (verified as most recent rating as of Jun 17, 2020).

Figure 9: Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire, Inc.	SR

Q44. Did you include New Jersey Resources Corporation (NJR) in your proxy group?

A44. No, I did not. New Jersey Resources Corporation (NJR) does not currently meet the screening criterion of deriving more than 70.00 percent of its total operating income from regulated operations over the three-year period 2017 to 2019. However, I have presented my ROE results including as well as excluding NJR.

VI. COST OF EQUITY ESTIMATION

Q45. Please briefly discuss the ROE in the context of the regulated rate of return (ROR).

A45. The ROE is the cost rate applied to the equity capital in the ROR. The ROR for a regulated utility is the weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and therefore must be estimated based on market data.

Q46. How is the required ROE determined?

A46. The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, as adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as of the subject company (in the context of the proxy group) in particular.

Q47. What methods did you use to determine Montana-Dakota's required ROE?

A47. I considered the results of the Constant Growth DCF model, the CAPM, the ECAPM, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q48. Why is it important to use more than one analytical approach?

A48. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[37] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[38] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q49. Do current market conditions increase the importance of using more than one analytical approach?

A49. Yes, they do. Low interest rates and the effects of the investor "flight to quality" can be seen in high utility share valuations, relative to historical levels and relative to the broader market. Higher utility stock valuations produce lower dividend yields and result in lower cost of equity estimates from a DCF analysis. Low interest rates also affect the CAPM in two ways: (1) the risk-free rate is lower, and (2) because the market risk premium is a function of interest rates, (i.e., it is the return on the broad stock market, less the risk-free interest rate), the risk premium should move higher when interest rates are lower. Therefore, it is important to use multiple analytical approaches to moderate the impact that the current low interest rate environment is having on the ROE estimates for the proxy group; and it is

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[37] Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

[38] Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

important to consider using, where possible, projected market data in the models to estimate the return for the forward-looking period.

Q50. What are your conclusions about the results of the DCF and CAPM models?

A50. Recent market data that is used as the basis for the assumptions for both models have been affected by market conditions. As a result, relying exclusively on historical assumptions in these models, without considering whether these assumptions are consistent with investors' future expectations, will underestimate the cost of equity that investors would require over the period that the rates in this case are to be in effect. In this instance, relying on the historically low dividend yields that are not expected to continue over the period that the new rates will be in effect will underestimate the ROE for Montana-Dakota.

Furthermore, as discussed in Section IV above, Treasury bond yields have experienced unprecedented volatility in recent months due to the economic effects of COVID-19 and the subsequent intervention into the Treasury bond market by the Federal Reserve. Therefore, the use of current averages of Treasury bond yields as the estimate of the risk-free rate in the CAPM is not appropriate, since recent market conditions are not expected to continue over the long-term. Instead, analysts should rely on projected yields of Treasury Bonds in the CAPM. Projected Treasury Bond yields produce CAPM results that are more reflective of the market conditions that investors expect for the period that the Company's rates will be in effect.

B. Constant Growth DCF Model

Q51. Please describe the DCF approach.

A51. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q52. What assumptions are required for the Constant Growth DCF model?

A52. The Constant Growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q53. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A53. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended July 31, 2020.

Q54. Why did you use 30-, 90-, and 180-day averaging periods?

A54. In my Constant Growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long-term. However, the averaging periods that I use rely on historical data that are not consistent with the forward-looking market expectations. Therefore, the results of my Constant Growth DCF model using historical data may underestimate the forward-looking cost of equity. As a result, I place more weight on the mean to mean-high results produced by my Constant Growth DCF model.

Q55. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A55. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model.

This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q56. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A56. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model.

Q57. Which sources of long-term earnings growth rates did you use?

A57. My Constant Growth DCF model incorporates three sources of long-term earnings growth rates: (1) Zacks Investment Research; (2) Thomson First Call (provided by Yahoo!Finance); and (3) Value Line Investment Survey.

C. <u>Discounted Cash Flow Model Results</u>

Q58. How did you calculate the range of results for the Constant Growth DCF Models?

A58. I calculated the low result for my DCF model using the minimum growth rate (*i.e.*, the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all sources.

Q59. Have you excluded any of the DCF results for individual companies in your proxy group?

A59. Yes, I have. It is appropriate to exclude Constant Growth DCF results below a specified threshold at which equity investors would consider such returns to provide an insufficient return increment above long-term debt costs. The average credit rating for the companies in my proxy group is between an A- and A.[39] The average yield on Moody's A-rated utility bonds for the 30 trading days ending July 31, 2020, was 2.82 percent.[40] As shown in Exhibit No.___(AEB-2), Schedule 4, I have eliminated Constant Growth DCF results lower than 7.00% because such returns would provide equity investors a risk premium only 418 basis points above A-rated utility bonds.

Q60. What were the results of your Constant Growth DCF analyses?

A60. Figure 10 summarizes the results of my DCF analyses. As shown in Figure 10, the mean DCF results for the proxy group range from 9.78 percent to 10.23 percent.

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[39] The average credit rating is calculated by assigning a numerical scale of 1 to 22 to the range of S&P and Moody's rating tiers. For the proxy group excluding NJR, the average is 16.2, and for the proxy group plus NJR, the average is 16.6. In both cases, these correspond to an average rating of between A- and A on the S&P scale.

[40] Source: Bloomberg Professional.

Figure 10: Constant Growth Discounted Cash Flow Results[41]

	Mean Low	Mean	Mean High
30-Day Average	9.72%	10.23%	11.31%
90-Day Average	9.51%	10.02%	11.11%
180-Day Average	9.78%	9.78%	10.87%

Q61. What are your conclusions about the results of the DCF models?

A61. As discussed previously, one primary assumption of the DCF models is a constant P/E ratio. That assumption is heavily influenced by the market price of utility stocks. To the extent that utility valuations are high and may not be sustainable, it is important to consider the results of the DCF models with caution. As discussed in Section IV above, while dividend yields have increased slightly due to the declines in utility share prices as a result of the economic effects of COVID-19, they are still low historically. This demonstrates that the results of the current DCF models are significantly below more normal market conditions. Therefore, while I have given weight to the results of the Constant Growth DCF model, my recommendation also gives weight to the results of other ROE estimation models.

D. <u>CAPM Analysis</u>

Q62. Please briefly describe the Capital Asset Pricing Model.

A62. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate

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[41] *See* Exhibit No.___(AEB-2), Schedule 4. Results displayed in the table above are for the proxy group of six companies, not including NJR. For the proxy group plus NJR, the mean ranges from 10.06 percent to 10.48 percent, and the mean-high ranges from 11.09 percent to 11.52 percent.

investors for the non-diversifiable or "systematic" risk of that security. This second component is the product of the market risk premium and the Beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta\left(r_m - r_f\right) \quad [3]$$

Where:

K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

In this specification, the term (rm – rf) represents the market risk premium. According to the theory underlying the CAPM because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by

Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (i.e., Variance (rm)) is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the general market (i.e., Covariance (re, rm)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q63. What risk-free rate did you use in your CAPM analysis?

A63. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 1.34 percent;[42] (2) the average projected 30-year U.S. Treasury bond yield for the fourth quarter of 2020 through the fourth quarter of 2021, which is 1.70 percent;[43] and (3) the average projected 30-year U.S. Treasury bond yield for 2022 through 2026, which is 3.00 percent.[44]

Q64. Would you place more weight on one of these scenarios?

A64. Yes, I would. Based on current market conditions, I place more weight on the results of the projected yields on the 30-year Treasury bonds. As discussed previously, the estimation of the cost of equity in this case should be forward-looking because it is the return that investors would receive over the future rate period. Therefore, the inputs and assumptions used in the CAPM analysis should reflect the expectations of the market at that time. While I have included the results of a CAPM analysis that relies on the current average risk-free rate, this analysis

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[42] Bloomberg Professional, as of July 31, 2020.
[43] Blue Chip Financial Forecasts, Vol. 39, No. 8, August 1, 2020, at 2.
[44] Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14.

fails to take into consideration the effect of the market's expectations for interest rate increases on the cost of equity.

Q65. What Beta coefficients did you use in your CAPM analysis?

A65. As shown on Exhibit No.___(AEB-2), Schedule 5, I used the Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The Beta coefficients reported by Bloomberg were calculated using ten years of weekly returns relative to the S&P 500 Index. Value Line's calculation is based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

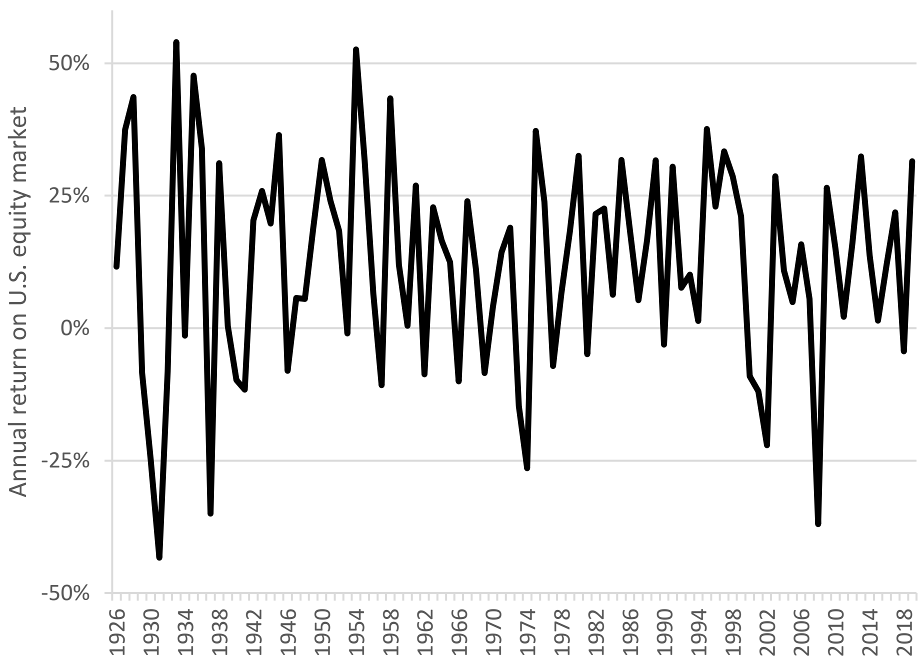
Q66. How did you estimate the market risk premium in the CAPM?

A66. I estimated the market risk premium based on the expected return on the S&P 500 Index less the yield on the 30-year Treasury bond. I calculated the expected return on the S&P 500 Index using publicly available data: S&P's published dividend yield and five-year projected growth rate for the entire S&P 500 Index. As shown in Exhibit No.___(AEB-2), Schedule 5, based on S&P's five-year growth rate for the S&P 500 of 12.12 percent and dividend yield of 1.72 percent, the expected return on the S&P 500 Index is 13.95 percent. As a result, the implied market risk premium over the current 30-day average of the 30-year U.S. Treasury bond yield, and over projected yields on the 30-year U.S. Treasury bond, ranges from 10.95 percent to 12.60 percent.

Q67. How does the current expected market return of 13.95 percent compare to historical observed market returns?

A67. Given the range of annual equity returns that have been observed over the past century (shown in Figure 11), a current expected return of 13.95 is not unreasonable. In 47 out of the past 94 years (or 50 percent of observations), the realized equity return was at least 13.95 or greater**.**

Figure 11: Realized U.S. equity market returns 1926-2019 [45]



Q68. Did you consider another form of the CAPM in your analysis?

A68. Yes. I have also considered the results of an Empirical CAPM ("ECAPM")[46] in estimating the cost of equity for Montana-Dakota. The ECAPM calculates the

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[45] Depicts total annual returns on large company stocks, as reported in the 2020 Duff and Phelps SBBI Yearbook**.**

[46] *See e.g.*, Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189.

product of the adjusted Beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required market ROE;

β = Adjusted Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In essence, the Empirical form of the CAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low Beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted Betas; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[47]

[47] *Id.,* at 191.

As with the CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the Bloomberg and Value Line Beta coefficients.

Q69. What are the results of your CAPM analyses?

A69. As shown in Figure 12 (see also Exhibit No.___(AEB-2), Schedule 5), my traditional CAPM analysis produces a range of returns from 11.86 percent to 12.21 percent for the proxy group.[48] The ECAPM analysis results range from 12.38 percent to 12.65 percent for the proxy group.[49] Thus, the range established for the proxy group by the traditional CAPM and the ECAPM is 11.86 percent to 12.65 percent with a mean of 12.26 percent.

[48] For the proxy group plus NJR, the CAPM range is 11.89 percent to 12.30 percent.
[49] For the proxy group plus NJR, the ECAPM range is 12.40 percent to 12.71 percent.

Figure 12: CAPM Results[50]

	Current Risk-Free Rate (1.34%)	Q4 2020–Q4 2021 Projected Risk-Free Rate (1.70%)	2022-2026 Projected Risk-Free Rate (3.00%)
CAPM			
Value Line Beta	11.95%	12.01%	12.21%
Bloomberg Beta	11.86%	11.92%	12.13%
ECAPM			
Value Line Beta	12.45%	12.49%	12.65%
Bloomberg Beta	12.38%	12.43%	12.59%

E. Bond Yield Plus Risk Premium Analysis

Q70. Please describe the Bond Yield Plus Risk Premium approach.

A70. This approach is based on the fundamental principle that because bondholders have a superior right to be repaid, equity investors bear a residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a "risk free" class of bonds.

Q71. Are there other considerations that should be addressed in conducting this analysis?

A71. Yes, there are. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase, the

50 Results displayed are for the proxy group of six companies, not including NJR.

equity risk premium decreases, and vice versa. Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. In my analysis, I used actual authorized returns for natural gas utility companies and corresponding long-term Treasury yields as the historical measure of the cost of equity to determine the risk premium. If we let authorized ROEs for natural gas utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[51]

Q72. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A72. Yes, it is. Investors are aware of ROE awards in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors.

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[51] *See e.g.*, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. *See also* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, Financial Management, Spring 1986, at 66.

Q73. What did your Bond Yield Plus Risk Premium analysis reveal?

A73. As shown in Figure 13 below, from 1992 through July 2020, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from 653 natural gas utility rate cases from 1992 through July 2020 as reported by Regulatory Research Associates ("RRA").[52] This equation's coefficients were statistically significant at the 99.00 percent level.

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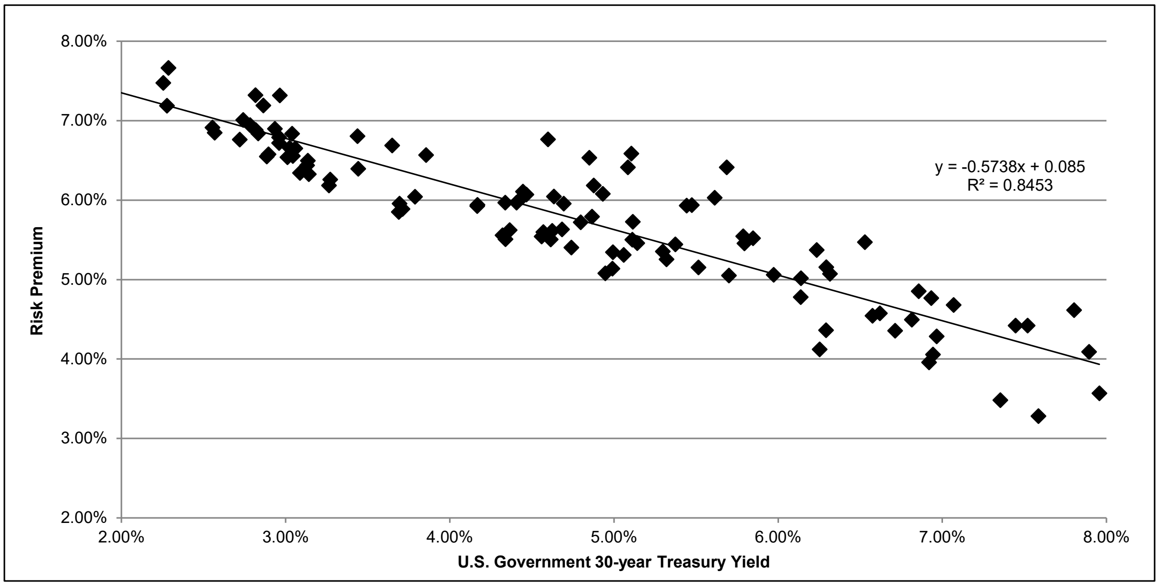
[52] This analysis began with a total of 1,040 cases which were screened to eliminate limited issue rider cases and cases that were silent with respect to the authorized ROE. After applying those screening criteria, the analysis was based on data for 653 cases.

Figure 13: Risk Premium Results



As shown on Exhibit No.___(AEB-2), Schedule 6, based on the current 30-day average of the 30-year U.S. Treasury bond yield (i.e., 1.34 percent), the risk premium would be 7.73 percent, resulting in an estimated ROE of 9.07 percent. Based on the near-term (Q4 2020 – Q4 2021) projections of the 30-year U.S. Treasury bond yield (i.e., 1.70 percent), the risk premium would be 7.52 percent, resulting in an estimated ROE of 9.22 percent. Based on longer-term (2022 – 2026) projections of the 30-year U.S. Treasury bond yield (i.e., 3.00 percent), the risk premium would be 6.78 percent, resulting in an estimated ROE of 9.78 percent.

Q74. How did the results of the Bond Yield Risk Premium inform your recommended ROE for Montana-Dakota?

A74. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for Montana-Dakota. As noted above, investors consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The risk premium analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of gas utilities across the US.

F. <u>Expected Earnings Analysis</u>

Q75. Have you considered any additional analysis to estimate the cost of equity for Montana-Dakota?

A75. Yes, I have. I considered an Expected Earnings analysis based on the projected ROEs for each of the proxy group companies.

Q76. What is an Expected Earnings Analysis?

A76. The Expected Earnings methodology is a comparable earnings analysis that calculates the earnings that an investor expects to receive on the book value of a stock. The expected earnings analysis is a forward-looking estimate of investors' expected returns. The use of an Expected Earnings approach based on the proxy companies provides a range of the expected returns on a group of risk comparable companies to the subject company. This range is useful in helping to determine the opportunity cost of investing in the subject company, which is relevant in determining a company's ROE.

Q77. Have any regulators considered the use of an Expected Earnings Analysis?

A77. Yes, they have. The Washington Utilities & Transportation Commission ("Washington UTC"), in its order in Dockets UE-170485 and UG-170486, considered the results of the Comparable Earnings analysis[53] in establishing the authorized ROE for Avista Corporation. The Washington UTC noted that it tends to place more weight on the results of the DCF, CAPM, and Risk Premium analyses; however, given the wide range of CAPM results presented by the ROE witnesses in the case, the Washington UTC decided to apply weight to the results of the Comparable Earnings analysis.[54] Specifically, the Washington UTC stated the following:

> Finally, as additional data points for our consideration of establishing Avista's ROE, we note that two witness, Mr. McKenzie for Avista and Mr. Parcell for Staff, employ the CE approach to two proxy groups of companies. The respective mid-points of each witnesses' CE analysis are 10.5 and 9.5 percent, respectively, with an average of 10.0 percent. Although we generally do not apply material weight to the CE method, having stronger reliance on the DCF, CAPM and RP methods, we are inclined to include the CE method here given the anomalous CAPM results described previously.[55]

Additionally, in its order in Docket No. ER12111052 for Jersey Central Power and Light Company, the New Jersey Board of Public Utilities ("NJ Board") noted that rate of return experts use a number of models including the DCF, CAPM, Risk Premium, and Comparable Earnings to estimate the return required by investors. Specifically, the Board noted:

> In determining the cost of equity capital for a regulated utility, rate of return experts typically use a variety of financial models to simulate the returns assertedly required by investors. These include

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53 The Expected Earnings analysis is a form of the Comparable Earnings analysis that relies exclusively on forward-looking projections.

54 *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket Nos. UE-170485 and UG-170486, Order 07, ¶ 65 (April 26,2018). Comparable Earnings as discussed in this docket is similar to the Expected Earnings analysis developed in my Direct Testimony.

55 *Ibid*.

> Discounted Cash Flow (DCF) models, Risk Premium models, Capital Asset Pricing Models (CAPM), Comparable Earnings models and variations thereof. However, it is widely acknowledged that these economic models constitute estimates, which, although probative, are not necessarily precise. The imprecision in the estimates provided by these models is more pronounced as a result of the current economic environment still recovering from the Great Recession, characterized by some as the worst economy since the Great Depression.[56]

Q78. How did you develop the Expected Earnings Approach?

A78. I relied primarily on the projected ROE capital for the proxy companies as reported by Value Line for the period from 2023-2025. However, I adjusted those projected ROEs to account for the fact that the ROEs reported by Value Line are calculated on the basis of common shares outstanding at the end of the period, as opposed to average shares outstanding over the period. As shown in Exhibit No.___(AEB-2), Schedule 7, the Expected Earnings analysis results in a mean of 10.08 percent for the proxy group.[57]

VII. REGULATORY AND BUSINESS RISKS

Q79. Do the DCF, CAPM, ECAPM, Bond Yield Plus Risk Premium, and Expected Earnings results for the proxy group, taken alone, provide an appropriate estimate of the cost of equity for Montana-Dakota?

A79. No, they do not. These results provide only a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity

[56] BPU Docket No. ER12111052, OAL Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, March 18, 2015, at 71.

[57] For the proxy group plus NJR, the mean is 10.07 percent.

falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Small Size Risk

Q80. Please explain the risk associated with small size.

A80. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[58]

Q81. How does the smaller size of a utility affect its business risk?

A81. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand

[58] Michael Annin, Equity and the Small-Stock Effect, Public Utilities Fortnightly, October 15, 1995.

reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q82. How does Montana-Dakota's natural gas distribution business in North Dakota compare in size to the proxy group companies?

A82. As noted previously, Montana-Dakota serves approximately 113,239 residential, commercial and industrial customers and, as of year-end 2019, had net utility natural gas plant in North Dakota of approximately $196.1 million.[59] Montana-Dakota's natural gas distribution operations in North Dakota are substantially smaller than the mean for the proxy group companies in terms of market capitalization. Exhibit No.___(AEB-2), Schedule 8 provides the actual market capitalization for the proxy group companies and estimates the implied market capitalization for Montana-Dakota (i.e., the implied market capitalization if Montana-Dakota's natural gas distribution operations in North Dakota were a stand-alone publicly-traded entity). To estimate the size of the Company's market capitalization relative to the proxy group, I calculated Montana-Dakota's proposed capital structure equity component of $98.65 million by multiplying Montana-Dakota's 2019 net utility plant in service of approximately $196.1 million by Montana-Dakota's projected common equity ratio of 50.306 percent. I then applied the average market-to-book ratio for the proxy group of 1.66 to Montana-Dakota's implied common equity balance and arrived at an implied market capitalization of

[59] Montana-Dakota Utilities, 2019 Annual Report to the North Dakota Public Service Commission, I. Intrastate Return on Equity, pp. 2 of 2, Line No. 3.

approximately $163.46 million, or 3.58 percent of the average market capitalization for the proxy group.[60]

Q83. How did you estimate the size premium for Montana-Dakota?

A83. Given this relative size information, it is possible to estimate the impact of size on the ROE for Montana-Dakota using Duff and Phelps data that estimates the stock risk premia based on the size of a company's market capitalization. As shown in Exhibit No.___(AEB-2), Schedule 8, the average market capitalization of the proxy group of approximately $4.57 billion corresponds to the fourth decile of the Duff and Phelps market capitalization data.[61] Based on Duff and Phelps' analysis, that decile corresponds to a size premium of 0.77 percent (i.e., 77 basis points). Montana-Dakota's implied market capitalization of approximately $163.46 million falls within the tenth decile, which comprises market capitalization levels up to $229.75 million and corresponds to a size premium of 4.99 percent (i.e., 499 basis points). The difference between those size premia is 422 basis points (i.e., 4.99 percent minus 0.77 percent).

Q84. Were utility companies included in the size premium study conducted by Duff and Phelps?

A84. Yes, they were. In fact, as shown in Exhibit 7.2 of Duff and Phelp's 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the

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[60] For the proxy group plus NJR, the average market-to-book ratio is 1.65, and the implied market cap is $162.64, which is 3.74 percent of the average of the proxy group including NJR.

[61] For the proxy group plus NJR, the mean market cap is $4.35 billion, which also corresponds to the fourth decile.

companies contained in the fourth decile.[62] Therefore, Duff and Phelp's did include utility companies in its size risk premium study.

Q85. Is the size premium applicable to companies in regulated industries such as natural gas utilities?

A85. Yes, it is. In fact, Stephanie Chretien and Frank Coggins in the article "Cost of Equity for Energy Utilities: Beyond the CAPM",[63] recently studied the CAPM and its ability to estimate the risk premium for the utility industry in particular subgroups of utilities. One of the subgroups was a group of natural gas distribution companies that contained many of the same natural gas distribution companies included in my proxy group.[64] The article considered the CAPM, the Fama-French three-factor model and a model similar to the Empirical CAPM that I have also considered above. In the article, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chretien and Coggins show the Beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[65] This demonstrates that the traditional CAPM model would not account for risk associated with small size.

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[62] Source: Duff &Phelps, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

[63] Chrétien, Stéphane, and Frank Coggins. "Cost Of Equity For Energy Utilities: Beyond The CAPM." *Energy Studies Review*, vol. 18, no. 2, 2011, doi:10.15173/esr.v18i2.531.

[64] The U.S. natural gas utility group included: AGL Resources Inc., Atmos Energy Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas Co., Piedmont Natural Gas Co., South Jersey Industries, Southwest Gas Corp. and WGL Holdings Inc.

[65] Chrétien, Stéphane, and Frank Coggins. "Cost Of Equity For Energy Utilities: Beyond The CAPM." *Energy Studies Review*, vol. 18, no. 2, 2011, doi:10.15173/esr.v18i2.531, at 31.

Q86. Have regulators in other jurisdictions made a specific risk adjustment to the ROE results based on a company's small size?

A86. Yes, they have. In Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk." [66] Thus, the RCA awarded AEL&P an ROE of 12.875 percent which was 108 basis points above the highest return on equity estimate from any model presented in the case.[67] Similarly, in Order No. 19, the RCA noted that small size as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions increased the risk of ENSTAR Natural Gas Company.[68] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[69]

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[66] Docket No. U-10-29, In the Matter of the Revenue Requirement and Cost of Service Study Designated as TA381-1 Filed by Alaska Electric Light and Power Company, Order entered September 2, 2011 (Order No. 15), at 37.

[67] *Id.*, at 32 and 37.

[68] Docket No. U-16-066, In the Matter of the Tariff Revision Designated as TA285-4 Filed by ENSTAR Natural Gas Company, A Division of SEMCO Energy, Inc., Order entered September 22, 2017 (Order No. 19), at 50-52.

[69] Ibid.

Additionally, in Docket No. E017/GR-15-1033 for Otter Tail Power Company ("Otter Tail"), the Minnesota Public Utilities Commission ("Minnesota PUC") selected an ROE above the mean DCF results, as a result of multiple factors including Otter Tail's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments.[70]

Q87. How have you considered the smaller size of Montana-Dakota in your recommendation?

A87. While I have estimated the effect of Montana-Dakota's small size on the ROE, I am not proposing a specific adjustment for this risk factor. Rather, I believe it is important to consider the small size of Montana-Dakota's natural gas distribution operations in North Dakota in the determination of where, within the range of analytical results, the Company's required ROE falls. Therefore, the additional risk associated with small size indicates that the Company's ROE should be established above the mean results for the proxy group companies.

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[70] Order in Docket No. E017/GR-15-1033, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota (August 16, 2016), at 55.

B. Flotation Cost

Q88. What are flotation costs?

A88. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q89. Why is it important to consider flotation costs in the allowed ROE?

A89. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected returns, thereby diluting equity share value.

Q90. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A90. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation cost is incurred prior to the test year but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny Montana-Dakota the opportunity to earn its required ROR in the future.

Q91. Please provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested.

A91. Suppose MDU Resources issues stock with a value of $100, and an equity investor invests $100 in MDU Resources in exchange for that stock. Further suppose that, after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, MDU Resources ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU Resources invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed.

Q92. Is the date of MDU Resources' last issued common equity important in the determination of flotation costs?

A92. No, it is not. As shown in Exhibit No.___(AEB-2), Schedule 8, MDU Resources closed on equity issuances of approximately $58 million and $54 million (for a total of 4.7 million shares of common stock) in November 2002 and February 2004, respectively. The vintage of the issuance, however, is not particularly important because the investor suffers a shortfall in every year that he should have a reasonable opportunity to earn a return on the full amount of capital that he has contributed. Returning to my earlier example, the investor who contributed $100 is entitled to a reasonable opportunity to earn a return on $100 not only in the first year after the investment, but in every subsequent year in which he has the $100 invested. Leaving aside depreciation, which is dealt with separately, there is no basis to conclude that the investor is entitled to earn a return on $100 in the first year after issuance, but thereafter is entitled to earn a return on only $97. As long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q93. Is the need to consider flotation costs recognized by the academic and financial communities?

A93. Yes, it is. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair ROR. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation

> costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[71]

Q94. How did you calculate the flotation costs for Montana-Dakota?

A94. My flotation cost calculation is based on the costs of issuing equity that were incurred by MDU Resources in its two most recent common equity issuances. Those issuance costs were applied to my proxy group. Applying the actual issuance costs for MDU Resources provided in Exhibit No.___(AEB-2), Schedule 9, to the DCF analysis, the flotation costs are estimated to be 0.14 percent (i.e., 14 basis points).[72]

Q95. Do your final results include an adjustment for flotation cost recovery?

A95. No, they do not. I did not make an explicit adjustment for flotation costs to any of my quantitative analyses. Rather, I provide the above result for consideration in my recommended ROE, which reflects the range of results from my Constant Growth DCF, CAPM, ECAPM, Bond Yield Plus Risk Premium, and Expected Earnings analyses.

C. Capital Expenditures

Q96. Please summarize the Company's capital expenditure requirements.

A96. The Company's current projections for 2021 through 2024 include approximately $89.8 million in capital investments for the period.[73] Based on the Company's 2019

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71 Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

72 For the proxy group plus NJR, the flotation costs are also estimated to be 0.14 percent (i.e., 14 basis points).

73 Data provided by Montana-Dakota Utilities Co.

net utility plant of approximately $196.1 million,[74] the $89.8 million of anticipated capital expenditures are approximately 45.82 percent of Montana-Dakota's 2019 net utility plant.

Q97. How is the Company's risk profile affected by their substantial capital expenditure requirements?

A97. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q98. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A98. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction

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[74] Montana-Dakota Utilities, 2019 Annual Report to the North Dakota Public Service Commission, I. Intrastate Return on Equity, pp. 2 of 2, Line No. 3

> work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[75]

Therefore, to the extent that Montana-Dakota's rates do not permit the opportunity to recover its capital investments on a regular basis, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q99. Does Montana-Dakota have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A99. No. Montana-Dakota currently does not recover capital investment costs between rate cases utilizing a capital tracking mechanism. Therefore, Montana-Dakota depends entirely on rate case filings for capital cost recovery. However, significant programs like Montana-Dakota's that drive capital expenditure requirements generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit No.___(AEB-2), Schedule 10, 12 out of 18 (67 percent) of the operating companies held by the proxy group recover costs through capital tracking mechanisms. Since Montana-Dakota does not currently have a capital tracking mechanism, Montana-Dakota's risk relative to the proxy group is increased.

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[75] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

Q100. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A100. The Company's capital expenditure requirements as a percentage of net utility plant are significant and will continue over the next few years. Additionally, unlike a number of the operating subsidiaries of the proxy group, Montana-Dakota does not have a comprehensive capital tracking mechanism to recover the Company's projected capital expenditures. Therefore, Montana-Dakota's significant capital expenditures plan and limited ability to recover the capital investment on an as-incurred basis results in a risk profile that is greater than that of the proxy group and supports an ROE toward the higher end of the reasonable range of ROEs.

D. Regulatory Risk

Q101. Please explain how the regulatory environment affects investors' risk assessments.

A101. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. Utilities must finance their operations and require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. Montana-Dakota is no exception. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q102. Please explain how credit rating agencies consider regulatory risk in establishing a company's credit rating.

A102. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3)

diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[76]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[77] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[78]

Q103. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A103. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility

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[76] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

[77] Standard & Poor's Global Ratings, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others, June 25, 2018, at 2.

[78] *Id*., at 1.

adapts to that environment are the most important credit considerations."[79] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[80]

Q104. Have you conducted any analysis of the regulatory framework in North Dakota relative to the jurisdictions in which the companies in your proxy group operate?

A104. Yes, I have. I evaluated the regulatory framework in North Dakota on four factors that are important in terms of providing a regulated utility an opportunity to earn its authorized ROE. These are: 1) prevalence of capital cost recovery between rate cases; 2) method for determining rate base (i.e., average vs. year-end); 3) use of revenue decoupling mechanisms or other clauses that mitigate volumetric risk; and 4) test year convention (i.e., forecast vs. historical). The results of this regulatory risk assessment are shown in Exhibit No.___(AEB-2), Schedule 10 and are summarized below.

<u>Capital Cost Recovery:</u> Montana-Dakota does not have a capital tracking mechanism to recover capital investment costs between rate cases. However, 12

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[79] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 6.

[80] *Ibid*.

out of 18 (67 percent) of the operating companies held by the proxy group have some form of capital cost recovery mechanism in place.

Rate Base: The Company's rate base in North Dakota is determined using the average rate base method, while 11 out of 18 (61 percent) of the operating companies held by the proxy group are allowed to use year-end rate base, meaning that the rate base includes capital additions that occurred in the second half of the test year and is more reflective of net utility plant going forward.

Volumetric Risk: Montana-Dakota does have some protection against volumetric risk in North Dakota. In its 2014 rate case settlement, Montana-Dakota was allowed to implement straight fixed-variable rates for its North Dakota residential gas distribution customers. This amounts to protection against volumetric risk for approximately 50 percent of its North Dakota natural gas distribution revenue. This is consistent with 16 out of 18 (89 percent) of the operating companies held by the proxy group that also have some form of protection against volumetric risk.

Test year convention: Montana-Dakota uses a projected future test year in North Dakota, which is consistent with 7 out of 18 (39 percent) of the operating companies held by the proxy group which provide service in jurisdictions that use a fully or partially forecast test year.

Q105. What are your conclusions regarding the perceived risks related to the North Dakota regulatory environment?

A105. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the proxy group have more timely cost recovery (through cost recovery trackers and more extensive revenue stabilization mechanisms) than Montana-Dakota has in North Dakota. Therefore, the average ROE for the proxy group would understate the return on equity that an investor would require in North Dakota because the risks of timely and full cost recovery are greater for Montana-Dakota in North Dakota than for the proxy group. For that reason, I conclude that the authorized ROE for Montana-Dakota should be higher than the proxy group mean.

VIII. CAPITAL STRUCTURE

Q106. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A106. Yes, it is. Assuming other factors equal, a higher debt ratio increases the risk to investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, who are the residual claimants on the cash flow of the Company. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q107. What is Montana-Dakota's proposed capital structure?

A107. The Company's proposal is to establish a capital structure consisting of 50.306 percent common equity, 42.37 percent long-term debt and 7.324 percent short-term debt.

Q108. Did you conduct any analysis to determine if this requested equity ratio was reasonable?

A108. Yes, I did. I reviewed the Company's proposed capital structure and the capital structures of the utility operating subsidiaries of the proxy companies. Because the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the proxy group average capital structure to benchmark the equity ratio for the Company.

Q109. Please discuss your analysis of the capital structures of the proxy group companies.

A109. I calculated the mean proportions of common equity, long-term debt, short-term debt and preferred equity for the most recent year for each of the companies in the proxy group at the operating subsidiary level.[81] My analysis of the capital structures of the proxy group companies is provided in Exhibit No.___(AEB-2), Schedule 11. As shown in Exhibit No.___(AEB-2), Schedule 11, the equity ratios for the proxy group ranged from 48.52 percent to 63.55 percent, with an average of 55.73 percent.[82] Montana-Dakota's proposed equity ratio of 50.306 is below the

[81] Source: SNL Financial and FERC Form 1 and FERC Form 2 annual reports.
[82] For the proxy group plus NJR, the range is the same, and the average is 56.18 percent.

average equity ratio for the utility operating subsidiaries of the proxy group companies and is therefore reasonable.

Q110. Are there other factors to be considered in setting the Company's capital structure?

A110. Yes, there are. The credit rating agencies' response to the TCJA must also be considered when determining the equity ratio. As discussed previously in my testimony, all three rating agencies have noted that the TCJA has negative implications for utility cash flows. Moody's unprecedented downgrade of the rating outlook for the entire utilities sector in June 2018 and continued downgrades of utilities since that time stresses the importance of maintaining adequate cash flow metrics for the industry as a whole and Montana-Dakota in the context of this proceeding.

Q111. Is there a relationship between the equity ratio and the authorized ROE?

A111. Yes, there is. The equity ratio is the primary indicator of financial risk for a regulated utility such as Montana-Dakota. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with greater leverage and the resulting increased fixed payment obligations.

Q112. What is your conclusion regarding an appropriate equity ratio for Montana-Dakota?

A112. Considering the actual capital structures of the proxy group operating companies, I believe that Montana-Dakota's proposed common equity ratio of 50.306 percent is reasonable. The proposed equity ratio is well withing the range of equity ratios established by the capital structures of the utility operating subsidiaries of the proxy companies. In addition, based on the cash flow concerns raised by credit rating agencies as a result of the TCJA, it is reasonable to rely on a higher equity ratio than the Company may have relied on previously.

IX. CONCLUSIONS AND RECOMMENDATION

Q113. What is your conclusion regarding a fair ROE for Montana-Dakota?

A113. Figure 14 below provides a summary of my analytical results for the proxy group.[83] Based on these results, the qualitative analyses presented in my Direct Testimony, the business and financial risks of Montana-Dakota compared to the proxy group, and the effects of Federal tax reform on the cash flow metrics of utilities, it is my view that an ROE of 10.20 percent is reasonable and would fairly balance the interests of customers and shareholders. This ROE would enable the Company to maintain its financial integrity and therefore its ability to attract capital at reasonable rates under a variety of economic and financial market conditions, while continuing to provide safe, reliable and affordable natural gas utility service to customers in North Dakota.

[83] For results based on the proxy group plus NJR, please see Exhibit No.___(AEB-2), Schedule 2.

Figure 14: Summary of Analytical Results[84] [85]

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average Price	9.72%	10.23%	11.31%
90-Day Average Price	9.51%	10.02%	11.11%
180-Day Average Price	9.78%	9.78%	10.87%
Capital Asset Pricing Model			
	Current Risk-Free Rate (1.34%)	Q4 2020-Q4 2021 Projected Risk-Free Rate (1.70%)	2022-2026 Projected Risk-Free Rate (3.00%)
Value Line Beta	11.95%	12.01%	12.21%
Bloomberg Beta	11.86%	11.92%	12.13%
Empirical Capital Asset Pricing Model			
Value Line Beta	12.45%	12.49%	12.65%
Bloomberg Beta	12.38%	12.43%	12.59%
Bond Yield Plus Risk Premium Analysis			
Risk Premium Analysis	9.07%	9.22%	9.78%
Expected Earnings Analysis			
Expected Earnings Results	10.08%		

Q114. What is your conclusion with respect to Montana-Dakota's proposed capital structure?

A114. My conclusion is that Montana-Dakota's proposal to establish a capital structure consisting of 50.306 percent common equity, 42.37 percent long-term debt and 7.324 percent short-term debt is reasonable when compared to the capital structures of the companies in the proxy group and taking in consideration the impact of the TCJA on the cash flows and therefore should be adopted.

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84 The analytical results displayed reflect the results of the Constant Growth DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7.00 percent.

85 Results displayed are for the proxy group of six companies, not including NJR. For results based on the proxy group plus NJR, please see Exhibit No.___(AEB-2), Schedule 2.

Q115. Does this conclude your Direct Testimony?

A115. Yes, it does.

ANN E. BULKLEY

Senior Vice President

Ms. Bulkley has more than two decades of management and economic consulting experience in the energy industry. Ms. Bulkley has extensive state and federal regulatory experience on both electric and natural gas issues including rate of return, cost of equity and capital structure issues. Ms. Bulkley has provided expert testimony on the cost of capital in more than 30 regulatory proceedings before regulatory commissions in Arizona, Arkansas, Colorado, Connecticut, Kansas, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, South Dakota, West Virginia, and the Federal Energy Regulatory Commission. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings. In addition, Ms. Bulkley has worked on acquisition teams with investors seeking to acquire utility assets, providing valuation services including an understanding of regulation, market expected returns, and the assessment of utility risk factors. Ms. Bulkley has assisted clients with valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and accounting and financial purposes. In addition, Ms. Bulkley has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring and regulatory and litigation support. Prior to joining Concentric, Ms. Bulkley held senior expertise-based consulting positions at several firms, including Reed Consulting Group and Navigant Consulting, Inc. where she specialized in valuation. Ms. Bulkley holds an M.A. in economics from Boston University and a B.A. in economics and finance from Simmons College. Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Analysis and Ratemaking

Ms. Bulkley has provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking. Specific services have included: cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies; development of merchant function exit strategies; analysis and program development to address residual energy supply and/or provider of last resort obligations; stranded costs assessment and recovery; performance-based ratemaking analysis and design; and many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation).

Cost of Capital

Ms. Bulkley has provided expert testimony on the cost of capital in more than 30 regulatory proceedings before regulatory commissions in Arizona, Arkansas, Colorado, Connecticut, Kansas, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, South Dakota, West Virginia, and the Federal Energy Regulatory Commission. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings in which she did not testify.

Valuation

Ms. Bulkley has provided valuation services to utility clients, unregulated generators and private equity clients for a variety of purposes including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Ms. Bulkley's appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Northern Indiana Fuel and Light: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Kokomo Gas: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost and comparable sales approaches.
- Confidential Utility Client: Prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

Ratemaking

Ms. Bulkley has assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.

Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Analyzed and evaluated rate application. Attended hearings and conducted investigation of rate application for regulatory staff. Prepared, supported and defended recommendations for revenue requirements and rates for the company. Developed rates for gas utility for transportation program and ancillary services.

Strategic and Financial Advisory Services

Ms. Bulkley has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Senior Vice President
Vice President
Assistant Vice President
Project Manager

Navigant Consulting, Inc. (1995 – 2002)
Project Manager

Cahners Publishing Company (1995)
Economist

EDUCATION

Boston University
M.A., Economics, 1995

Simmons College
B.A., Economics and Finance, 1991

CERTIFICATIONS

Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
PacifiCorp d/b/a Rocky Mountain Power	06/20	PacifiCorp d/b/a Rocky Mountain Power	PAC-E-20-03	Return on Equity
Indiana Utility Regulatory Commission				
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-00194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Massachusetts Department of Public Utilities				
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Allete, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Gas 17-G-0460 Electric 17-E-0459	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

SUMMARY OF ROE ANALYSES RESULTS [1]

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	9.72%	10.23%	11.31%
90-Day Average	9.51%	10.02%	11.11%
180-Day Average	9.78%	9.78%	10.87%
Constant Growth Average	9.67%	10.01%	11.10%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.95%	12.01%	12.21%
Bloomberg Beta	11.86%	11.92%	12.13%
ECAPM			
Value Line Beta	12.45%	12.49%	12.65%
Bloomberg Beta	12.38%	12.43%	12.59%
Bond Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Analysis	9.07%	9.22%	9.78%
Expected Earnings Analysis			
Expected Earnings Analysis	10.08%		

Notes:

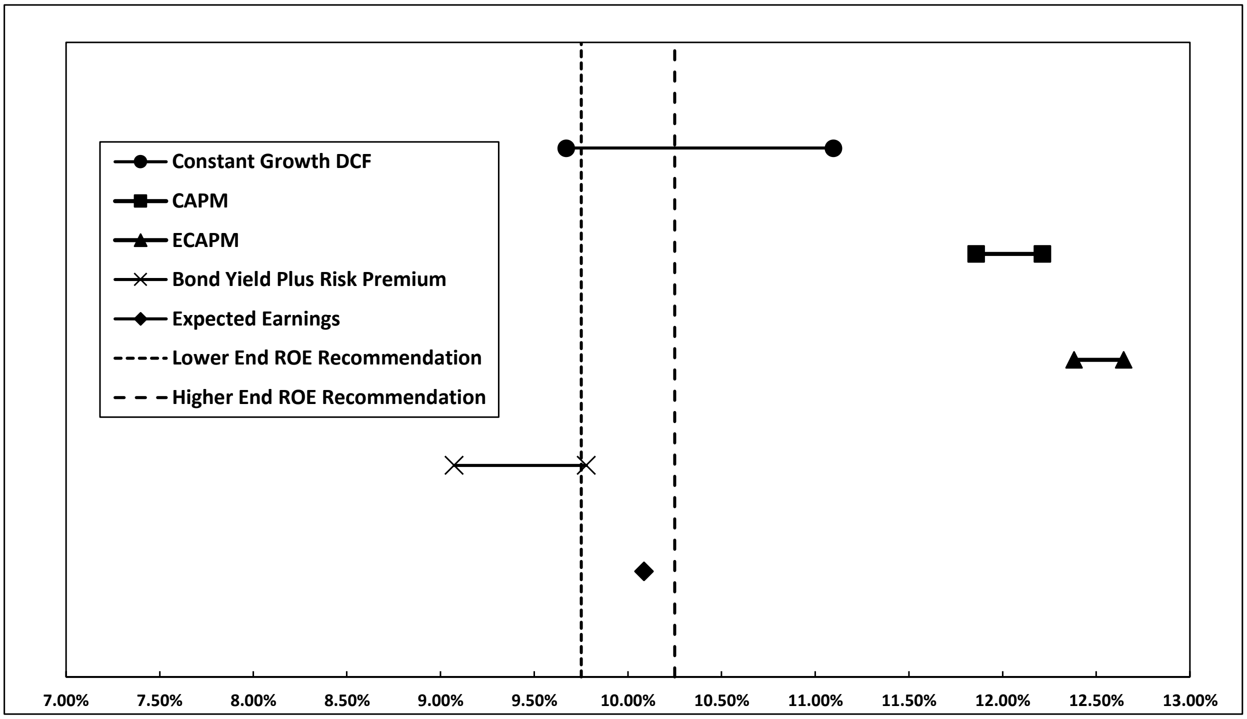
[1] The analytical results included in the table reflect the results of the Constant Growth DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7 percent.

SUMMARY OF ROE ANALYSES RESULTS INCLUDING NJR [1]

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	9.72%	10.48%	11.52%
90-Day Average	9.51%	10.27%	11.31%
180-Day Average	9.78%	10.06%	11.09%
Constant Growth Average	9.67%	10.27%	11.31%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	12.06%	12.11%	12.30%
Bloomberg Beta	11.89%	11.95%	12.16%
ECAPM			
Value Line Beta	12.53%	12.57%	12.71%
Bloomberg Beta	12.40%	12.45%	12.61%
Bond Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Analysis	9.07%	9.22%	9.78%
Expected Earnings Analysis			
Expected Earnings Analysis	10.07%		

Notes:

[1] The analytical results included in the table reflect the results of the Constant Growth DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7 percent.


Constant Growth DCF
CAPM
ECAPM
Bond Yield Plus Risk Premium
Expected Earnings
Lower End ROE Recommendation
Higher End ROE Recommendation
7.00%
7.50%
8.00%
8.50%
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11.00%
11.50%
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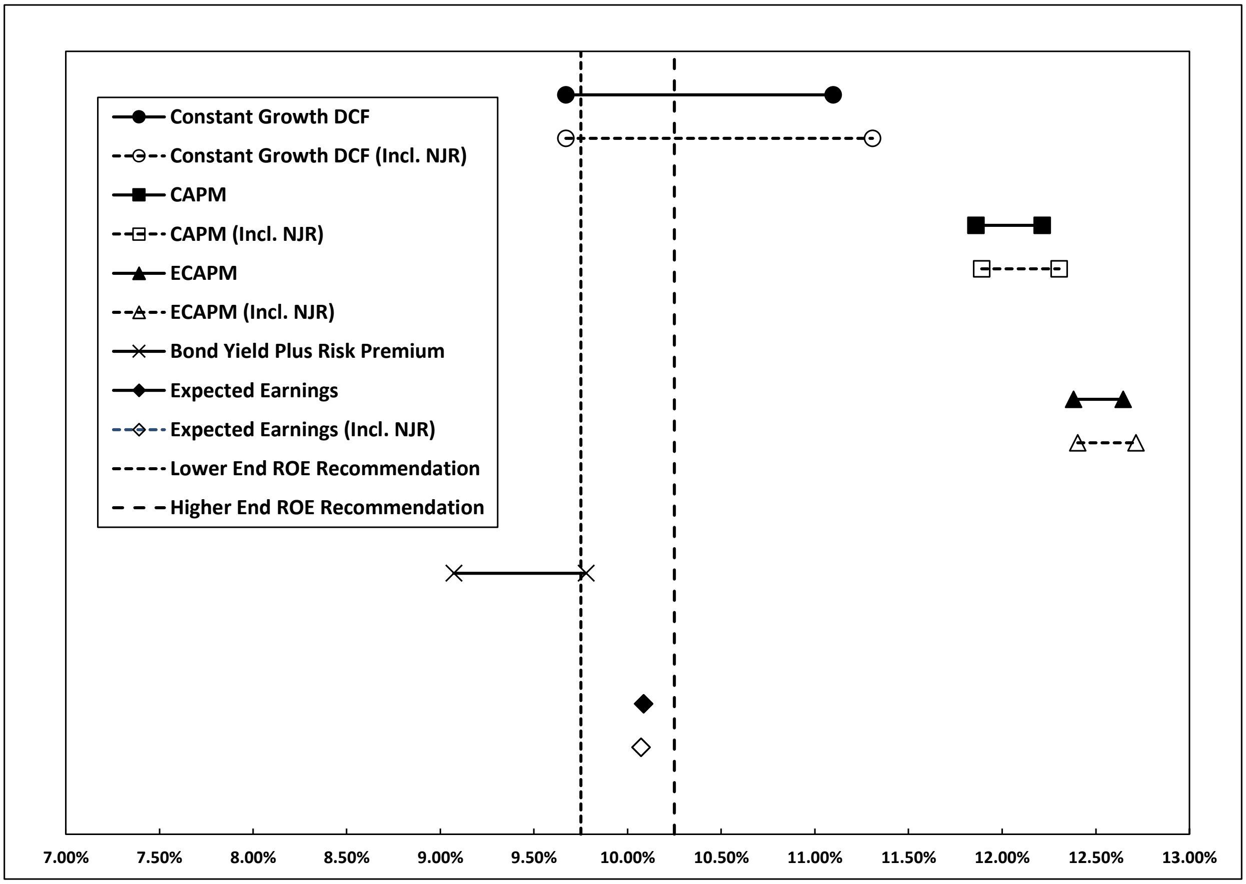
13.00%


Constant Growth DCF
Constant Growth DCF (Incl. NJR)
CAPM
CAPM (Incl. NJR)
ECAPM
ECAPM (Incl. NJR)
Bond Yield Plus Risk Premium
Expected Earnings
Expected Earnings (Incl. NJR)
Lower End ROE Recommendation
Higher End ROE Recommendation
7.00%
7.50%
8.00%
8.50%
9.00%
9.50%
10.00%
10.50%
11.00%
11.50%
12.00%
12.50%
13.00%

PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Dividends	S&P or Moody's Investment Grade Credit Rating	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	% Regulated Operating Income > 70%	% Regulated Natural Gas Operating Income > 60%	Announced Merger
Atmos Energy Corporation	ATO	Yes	A	Yes	100.00%	66.55%	No
Northwest Natural Gas Company	NWN	Yes	A+	Yes	100.00%	90.90%	No
ONE Gas Inc.	OGS	Yes	A	Yes	100.00%	100.00%	No
South Jersey Industries, Inc.	SJI	Yes	BBB	Yes	100.00%	100.00%	No
Southwest Gas Corporation	SWX	Yes	BBB+	Yes	80.46%	100.00%	No
Spire, Inc.	SR	Yes	A-	Yes	97.03%	100.00%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[4] Source: Form 10-K's for 2019, 2018, and 2017
[5] Source: Form 10-K's for 2019, 2018, and 2017
[6] Source: SNL Financial News Releases

30-DAY CONSTANT GROWTH DCF -- MDU NORTH DAKOTA PROXY GROUP

										All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	$2.30	$100.96	2.28%	2.36%	7.00%	7.15%	7.20%	7.12%	9.36%	9.48%	9.56%	9.36%	9.48%	9.56%
New Jersey Resources Corporation	NJR	$1.25	$31.58	3.96%	4.05%	2.00%	6.00%	6.00%	4.67%	6.00%	8.72%	10.08%		8.72%	10.08%
Northwest Natural Gas Company	NWN	$1.91	$53.91	3.54%	3.63%	7.56%	3.90%	3.90%	5.12%	7.51%	8.75%	11.24%	7.51%	8.75%	11.24%
ONE Gas Inc.	OGS	$2.16	$75.82	2.85%	2.93%	6.50%	5.00%	5.50%	5.67%	7.92%	8.60%	9.44%	7.92%	8.60%	9.44%
South Jersey Industries, Inc.	SJI	$1.18	$23.82	4.95%	5.23%	12.50%	10.30%	10.30%	11.03%	15.51%	16.26%	17.76%	15.51%	16.26%	17.76%
Southwest Gas Corporation	SWX	$2.28	$68.98	3.31%	3.43%	8.00%	8.20%	6.00%	7.40%	9.40%	10.83%	11.64%	9.40%	10.83%	11.64%
Spire, Inc.	SR	$2.49	$64.57	3.86%	3.95%	5.50%	4.67%	4.80%	4.99%	8.62%	8.94%	9.46%	8.62%	8.94%	9.46%
Mean				3.46%	3.59%	7.84%	6.54%	6.28%	6.89%	9.72%	10.48%	11.52%	9.72%	10.23%	11.31%
Mean Incl. NJR						7.01%	6.46%	6.24%	6.57%	9.19%	10.23%	11.31%	9.72%	10.48%	11.52%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2020.
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] - [14] Excludes companies with ROEs less than the a 7.00% return.

90-DAY CONSTANT GROWTH DCF -- MDU NORTH DAKOTA PROXY GROUP

										All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	$2.30	$100.88	2.28%	2.36%	7.00%	7.15%	7.20%	7.12%	9.36%	9.48%	9.56%	9.36%	9.48%	9.56%
New Jersey Resources Corporation	NJR	$1.25	$32.74	3.82%	3.91%	2.00%	6.00%	6.00%	4.67%	5.86%	8.57%	9.93%		8.57%	9.93%
Northwest Natural Gas Company	NWN	$1.91	$59.27	3.22%	3.31%	7.56%	3.90%	3.90%	5.12%	7.19%	8.43%	10.91%	7.19%	8.43%	10.91%
ONE Gas Inc.	OGS	$2.16	$79.56	2.72%	2.79%	6.50%	5.00%	5.50%	5.67%	7.78%	8.46%	9.30%	7.78%	8.46%	9.30%
South Jersey Industries, Inc.	SJI	$1.18	$25.63	4.60%	4.86%	12.50%	10.30%	10.30%	11.03%	15.14%	15.89%	17.39%	15.14%	15.89%	17.39%
Southwest Gas Corporation	SWX	$2.28	$71.78	3.18%	3.29%	8.00%	8.20%	6.00%	7.40%	9.27%	10.69%	11.51%	9.27%	10.69%	11.51%
Spire, Inc.	SR	$2.49	$69.70	3.57%	3.66%	5.50%	4.67%	4.80%	4.99%	8.33%	8.65%	9.17%	8.33%	8.65%	9.17%
Mean				3.26%	3.38%	7.84%	6.54%	6.28%	6.89%	9.51%	10.27%	11.31%	9.51%	10.02%	11.11%
Mean Incl. NJR						7.01%	6.46%	6.24%	6.57%	8.99%	10.02%	11.11%	9.51%	10.27%	11.31%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2020.
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] - [14] Excludes companies with ROEs less than the a 7.00% return.

180-DAY CONSTANT GROWTH DCF -- MDU NORTH DAKOTA PROXY GROUP

										All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	$2.30	$105.49	2.18%	2.26%	7.00%	7.15%	7.20%	7.12%	9.26%	9.37%	9.46%	9.26%	9.37%	9.46%
New Jersey Resources Corporation	NJR	$1.25	$36.82	3.39%	3.47%	2.00%	6.00%	6.00%	4.67%	5.43%	8.14%	9.50%		8.14%	9.50%
Northwest Natural Gas Company	NWN	$1.91	$64.70	2.95%	3.03%	7.56%	3.90%	3.90%	5.12%	6.91%	8.15%	10.63%		8.15%	10.63%
ONE Gas Inc.	OGS	$2.16	$84.58	2.55%	2.63%	6.50%	5.00%	5.50%	5.67%	7.62%	8.29%	9.14%	7.62%	8.29%	9.14%
South Jersey Industries, Inc.	SJI	$1.18	$28.02	4.21%	4.44%	12.50%	10.30%	10.30%	11.03%	14.73%	15.48%	16.98%	14.73%	15.48%	16.98%
Southwest Gas Corporation	SWX	$2.28	$72.66	3.14%	3.25%	8.00%	8.20%	6.00%	7.40%	9.23%	10.65%	11.47%	9.23%	10.65%	11.47%
Spire, Inc.	SR	$2.49	$75.11	3.31%	3.40%	5.50%	4.67%	4.80%	4.99%	8.06%	8.39%	8.91%	8.06%	8.39%	8.91%
Mean				3.06%	3.17%	7.84%	6.54%	6.28%	6.89%	9.30%	10.06%	11.09%	9.78%	9.78%	10.87%
Mean Incl. NJR						7.01%	6.46%	6.24%	6.57%	8.75%	9.78%	10.87%	9.78%	10.06%	11.09%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2020.
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] - [14] Excludes companies with ROEs less than the a 7.00% return.

Actual and Alternative Calculation of Northwest Natural's Projected Earnings Growth Rate from Value Line

[1]		[2]	[3]
Actual Earnings Per Share		Projected Earnings Per Share (2023-2025)	Projected Earnings Growth Rate
2017	-1.94		
2018	2.33		
2019	2.19		
Mean (2017-2019)	0.86	3.5	26.36%
Mean (2018-2019)	2.26	3.5	7.56%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals ([2] / [1]) ^ (1/6) - 1

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] CAPM ROE	[6] ECAPM ROE
Atmos Energy Corporation	ATO	1.34%	0.80	13.95%	12.60%	11.43%	12.06%
New Jersey Resources Corporation	NJR	1.34%	0.90	13.95%	12.60%	12.69%	13.00%
Northwest Natural Gas Company	NWN	1.34%	0.80	13.95%	12.60%	11.43%	12.06%
ONE Gas Inc.	OGS	1.34%	0.80	13.95%	12.60%	11.43%	12.06%
South Jersey Industries, Inc.	SJI	1.34%	0.95	13.95%	12.60%	13.32%	13.47%
Southwest Gas Corporation	SWX	1.34%	0.90	13.95%	12.60%	12.69%	13.00%
Spire, Inc.	SR	1.34%	0.80	13.95%	12.60%	11.43%	12.06%
Mean						11.95%	12.45%
Mean Incl. NJR						12.06%	12.53%

Notes:
[1] Source: Bloomberg Professional, dated July 31, 2020
[2] Source: Value Line; dated May 29, 2020
[3] Source: Schedule-5, page 3
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VL BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2020 - Q4 2021)	Beta	Market Return	Market Risk Premium	CAPM ROE	ECAPM ROE
Atmos Energy Corporation	ATO	1.70%	0.80	13.95%	12.25%	11.50%	12.11%
New Jersey Resources Corporation	NJR	1.70%	0.90	13.95%	12.25%	12.72%	13.03%
Northwest Natural Gas Company	NWN	1.70%	0.80	13.95%	12.25%	11.50%	12.11%
ONE Gas Inc.	OGS	1.70%	0.80	13.95%	12.25%	11.50%	12.11%
South Jersey Industries, Inc.	SJI	1.70%	0.95	13.95%	12.25%	13.33%	13.49%
Southwest Gas Corporation	SWX	1.70%	0.90	13.95%	12.25%	12.72%	13.03%
Spire, Inc.	SR	1.70%	0.80	13.95%	12.25%	11.50%	12.11%
Mean						12.01%	12.49%
Mean Incl. NJR						12.11%	12.57%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 8, August 1, 2020, at 2
[2] Source: Value Line; dated May 29, 2020
[3] Source: Schedule-5, page 3
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2022 - 2026)	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] CAPM ROE	[6] ECAPM ROE
Atmos Energy Corporation	ATO	3.00%	0.80	13.95%	10.95%	11.76%	12.30%
New Jersey Resources Corporation	NJR	3.00%	0.90	13.95%	10.95%	12.85%	13.13%
Northwest Natural Gas Company	NWN	3.00%	0.80	13.95%	10.95%	11.76%	12.30%
ONE Gas Inc.	OGS	3.00%	0.80	13.95%	10.95%	11.76%	12.30%
South Jersey Industries, Inc.	SJI	3.00%	0.95	13.95%	10.95%	13.40%	13.54%
Southwest Gas Corporation	SWX	3.00%	0.90	13.95%	10.95%	12.85%	13.13%
Spire, Inc.	SR	3.00%	0.80	13.95%	10.95%	11.76%	12.30%
Mean						12.21%	12.65%
Mean Incl. NJR						12.30%	12.71%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[2] Source: Value Line; dated May 29, 2020
[3] Source: Schedule-5, page 3
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	CAPM ROE	ECAPM ROE
Atmos Energy Corporation	ATO	1.34%	0.79	13.95%	12.60%	11.24%	11.91%
New Jersey Resources Corporation	NJR	1.34%	0.85	13.95%	12.60%	12.07%	12.54%
Northwest Natural Gas Company	NWN	1.34%	0.76	13.95%	12.60%	10.86%	11.63%
ONE Gas Inc.	OGS	1.34%	0.85	13.95%	12.60%	12.02%	12.50%
South Jersey Industries, Inc.	SJI	1.34%	0.87	13.95%	12.60%	12.35%	12.75%
Southwest Gas Corporation	SWX	1.34%	0.93	13.95%	12.60%	13.09%	13.31%
Spire, Inc.	SR	1.34%	0.81	13.95%	12.60%	11.60%	12.18%
Mean						11.86%	12.38%
Mean Incl. NJR						11.89%	12.40%

Notes:
[1] Source: Bloomberg Professional, dated July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Schedule-5, page 3
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2020 - Q4 2021)	Beta	Market Return	Market Risk Premium	CAPM ROE	ECAPM ROE
Atmos Energy Corporation	ATO	1.70%	0.79	13.95%	12.25%	11.31%	11.97%
New Jersey Resources Corporation	NJR	1.70%	0.85	13.95%	12.25%	12.13%	12.58%
Northwest Natural Gas Company	NWN	1.70%	0.76	13.95%	12.25%	10.95%	11.70%
ONE Gas Inc.	OGS	1.70%	0.85	13.95%	12.25%	12.07%	12.54%
South Jersey Industries, Inc.	SJI	1.70%	0.87	13.95%	12.25%	12.39%	12.78%
Southwest Gas Corporation	SWX	1.70%	0.93	13.95%	12.25%	13.12%	13.32%
Spire, Inc.	SR	1.70%	0.81	13.95%	12.25%	11.66%	12.23%
Mean						11.92%	12.43%
Mean Incl. NJR						11.95%	12.45%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 8, August 1, 2020, at 2
[2] Source: Bloomberg Professional
[3] Source: Schedule-5, page 3
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2022 - 2026)	Beta	Market Return	Market Risk Premium	CAPM ROE	ECAPM ROE
Atmos Energy Corporation	ATO	3.00%	0.79	13.95%	10.95%	11.59%	12.18%
New Jersey Resources Corporation	NJR	3.00%	0.85	13.95%	10.95%	12.32%	12.73%
Northwest Natural Gas Company	NWN	3.00%	0.76	13.95%	10.95%	11.27%	11.94%
ONE Gas Inc.	OGS	3.00%	0.85	13.95%	10.95%	12.27%	12.69%
South Jersey Industries, Inc.	SJI	3.00%	0.87	13.95%	10.95%	12.56%	12.90%
Southwest Gas Corporation	SWX	3.00%	0.93	13.95%	10.95%	13.21%	13.39%
Spire, Inc.	SR	3.00%	0.81	13.95%	10.95%	11.91%	12.42%
Mean						12.13%	12.59%
Mean Incl. NJR						12.16%	12.61%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[2] Source: Bloomberg Professional
[3] Source: Schedule-5, page 3
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

MARKET RISK PREMIUM DERIVED FROM S&P EARNINGS AND ESTIMATE REPORT

[7] S&P's estimate of the S&P 500 Dividend Yield	1.72%
[8] S&P's estimate of the S&P 500 Growth Rate	12.12%
[9] S&P 500 Estimated Required Market Return	13.95%

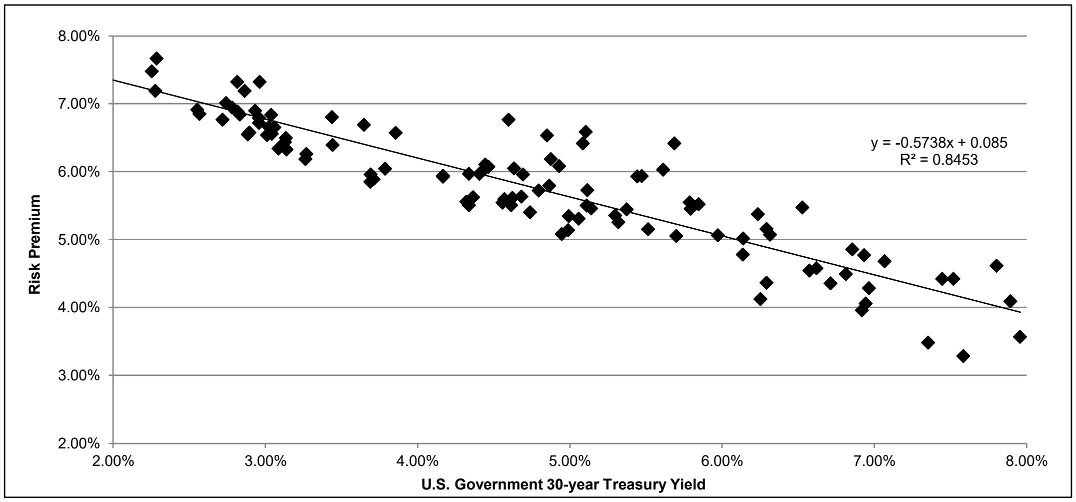
Notes:
[7] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, July 31, 2020
[8] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, July 31, 2020
[9] Equals ([7] x (1 + (0.5 x [8]))) + [8]

Risk Premium -- Natural Gas Utilities (US)

	[1] Average Authorized Gas ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.42%	7.80%	4.62%
1992.2	11.98%	7.89%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.31%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.57%	4.55%
1994.2	10.84%	7.35%	3.48%
1994.3	10.87%	7.58%	3.28%
1994.4	11.53%	7.96%	3.57%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.71%	4.35%
1995.4	11.61%	6.23%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.96%
1996.3	11.25%	6.96%	4.29%
1996.4	11.19%	6.62%	4.58%
1997.1	11.31%	6.81%	4.49%
1997.2	11.70%	6.93%	4.77%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.14%	4.78%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.47%	5.94%
1998.4	11.69%	5.10%	6.59%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.79%	5.46%
1999.4	10.38%	6.25%	4.12%
2000.1	10.66%	6.29%	4.36%
2000.2	11.03%	5.97%	5.06%
2000.3	11.33%	5.79%	5.55%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.44%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.51%	5.15%
2002.2	11.64%	5.61%	6.03%
2002.3	11.50%	5.08%	6.42%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.32%	5.25%
2004.3	10.37%	5.06%	5.31%
2004.4	10.66%	4.86%	5.79%
2005.1	10.65%	4.69%	5.96%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.44%	6.03%
2005.4	10.32%	4.68%	5.63%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	4.99%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%

Risk Premium -- Natural Gas Utilities (US)

	[1]	[2]	[3]
	Average Authorized Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.60%
2008.3	10.55%	4.44%	6.11%
2008.4	10.34%	3.65%	6.69%
2009.1	10.24%	3.44%	6.81%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.36%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.93%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.69%	5.96%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.93%	6.90%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.26%	6.19%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.72%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.04%	6.56%
2017.2	9.47%	2.90%	6.58%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.66%
2019.4	9.73%	2.25%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.40%	1.31%	8.09%
AVERAGE	10.48%	4.66%	5.83%
MEDIAN	10.38%	4.63%	5.93%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.919419473
R Square	0.845332167
Adjusted R Square	0.843913196
Standard Error	0.003927645
Observations	111

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.009190058	0.009190058	595.7360629	5.49926E-46
Residual	109	0.001681477	1.54264E-05		
Total	110	0.010871535			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.084995875	0.001157004	73.46201858	1.12743E-94	0.08270273	0.08728902	0.08270273	0.08728902
X Variable 1	-0.57383535	0.023510418	-24.40770499	5.49926E-46	-0.620432235	-0.5272385	-0.620432235	-0.527238466

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	1.34%	7.73%	9.07%
Blue Chip Near-Term Projected Forecast (Q4 2020 - Q4 2021) [5]	1.70%	7.52%	9.22%
Blue Chip Long-Term Projected Forecast (2022-2026) [6]	3.00%	6.78%	9.78%
AVERAGE			9.36%

Notes:
[1] Source: Regulatory Research Associates, rate cases through July 31, 2020
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of July 31, 2020
[5] Source: Blue Chip Financial Forecasts, Vol. 39, No. 8, August 1, 2020, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.084996 + (-0.573835 x Column [7])
[9] Equals Column [7] + Column [8]

EXPECTED EARNINGS ANALYSIS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Value Line ROE 2023-2025	Value Line Total Capital 2019	Value Line Common Equity Ratio 2019	Total Equity 2019	Value Line Total Capital 2023-2025	Value Line Common Equity Ratio 2023-2025	Total Equity 2023-2025	Compound Annual Growth Rate	Adjustment Factor	Adjusted Return on Common Equity
Atmos Energy Corporation	ATO	9.00%	9,279.70	62.00%	5,753	16,000	60.00%	9,600	10.78%	1.051	9.46%
New Jersey Resources Corporation	NJR	9.50%	3,088.90	50.20%	1,551	4,580	56.50%	2,588	10.79%	1.051	9.99%
Northwest Natural Gas Company	NWN	11.50%	1,672.00	51.80%	866	1,825	52.50%	958	2.04%	1.010	11.62%
One Gas Inc.	OGS	9.50%	3,415.50	62.30%	2,128	4,400	62.00%	2,728	5.09%	1.025	9.74%
South Jersey Industries, Inc.	SJI	12.00%	3,493.90	40.80%	1,426	4,850	43.50%	2,110	8.16%	1.039	12.47%
Southwest Gas Corporation	SWX	9.50%	4,806.40	52.10%	2,504	7,000	55.50%	3,885	9.18%	1.044	9.92%
Spire, Inc.	SR	7.00%	4,625.60	55.00%	2,544	7,200	55.00%	3,960	9.25%	1.044	7.31%
Mean											10.08%
Mean Incl. NJR											10.07%

Notes:
[1] Source: Value Line, May 29, 2020
[2] Source: Value Line, May 29, 2020
[3] Source: Value Line, May 29, 2020
[4] Equals [2] x [3]
[5] Source: Value Line, May 29, 2020
[6] Source: Value Line, May 29, 2020
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ billions)	[2] Market-to-Book Ratio
Atmos Energy Corporation	ATO	12.43	1.96
New Jersey Resources Corporation	NJR	3.03	1.60
Northwest Natural Gas Company	NWN	1.65	1.83
ONE Gas Inc.	OGS	4.01	1.83
South Jersey Industries, Inc.	SJI	2.20	1.47
Southwest Gas Corporation	SWX	3.84	1.49
Spire, Inc.	SR	3.31	1.36
Mean		4.57	1.66
Mean Incl. NJR		4.35	1.65

Montana-Dakota Utilities Co. - ND Natural Gas	
2019 Net Utility Plant in Service ($ millions) [3]	$ 196.10
Projected Common Equity Ratio [3]	50.306%
Implied Common Equity ($ millions) [4]	$ 98.65
Implied Market Capitalization ($ millions) [5]	$ 163.46
As a percent of Proxy Group Median Market Capitalization	3.58%

Duff & Phelps Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10	[6] Market Capitalization of Largest Company ($ millions)	[7] Size Premium
1-Largest	1,061,355.01	-0.27%
2	30,542.94	0.48%
3	13,100.23	0.69%
4	6,614.96	0.77%
5	4,311.25	1.08%
6	2,685.87	1.37%
7	1,668.28	1.47%
8	993.85	1.61%
9	515.60	2.26%
10-Smallest	229.75	4.99%
Montana-Dakota Utilities Co. - ND Natural Gas - Implied Market Capitalization	163.46	4.99%
Proxy Group Average Market Capitalization	4,572.22	0.77%
Size Premium [8]		4.22%

Notes:
[1] Source: SNL Financial; equals 30-day average as of July 31, 2020
[2] Source: SNL Financial; equals 30-day average as of July 31, 2020
[3] Data provided by Montana-Dakota Utilities Co.
[4] Equals net utility plant in service x projected common equity ratio
[5] Equals [4] x proxy group mean market-to-book ratio
[6] Duff & Phelps Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2019
[7] Duff & Phelps Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2019
[8] Equals 4.99% − 0.77%

FLOTATION COST ADJUSTMENT

Company	Date [i]	Shares Issued (000)	Offering Price	Under-writing Discount [ii]	Offering Expense ($000)	Net Proceeds Per Share	Total Flotation Costs ($000)	Equity Issue Before Costs ($000)	Net Proceeds ($000)	Flotation Cost Percentage
MDU Resources Group	2/4/2004	2,300	$ 23.32	0.79	$ 350	$ 22.37	$ 2,174	$ 53,636	$ 51,462	4.05%
MDU Resources Group	11/19/2002	2,400	$ 24.00	0.72	$ 193	$ 23.20	$ 1,921	$ 57,600	$ 55,680	3.33%
							$ 4,094	$ 111,236	$ 107,142	3.68%

Notes:
[i] Offering Completion Date
[ii] Underwriting discount was calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9632, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Expected Dividend Yield Adjusted for Flotation Costs	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Earnings Growth	ROE	ROE Adjusted for Flotation Costs
Atmos Energy Corporation	ATO	$2.30	$100.96	2.28%	2.36%	2.45%	7.00%	7.15%	7.20%	7.12%	9.48%	9.57%
New Jersey Resources Corporation	NJR	$1.25	$31.58	3.96%	4.05%	4.21%	2.00%	6.00%	6.00%	4.67%	8.72%	8.87%
Northwest Natural Gas Company	NWN	$1.91	$53.91	3.54%	3.63%	3.77%	7.56%	3.90%	3.90%	5.12%	8.75%	8.89%
ONE Gas Inc.	OGS	$2.16	$75.82	2.85%	2.93%	3.04%	6.50%	5.00%	5.50%	5.67%	8.60%	8.71%
South Jersey Industries, Inc.	SJI	$1.18	$23.82	4.95%	5.23%	5.43%	12.50%	10.30%	10.30%	11.03%	16.26%	16.46%
Southwest Gas Corporation	SWX	$2.28	$68.98	3.31%	3.43%	3.56%	8.00%	8.20%	6.00%	7.40%	10.83%	10.96%
Spire, Inc.	SR	$2.49	$64.57	3.86%	3.95%	4.10%	5.50%	4.67%	4.80%	4.99%	8.94%	9.09%
Mean											10.48%	10.61%
Flotation Cost Adjustment [12]												0.14%
Mean Incl. NJR											10.23%	10.36%
Flotation Cost Adjustment Incl. NJR [13]												0.14%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Equals [4] / (1 − Flotation Cost)
[6] Source: Value Line
[7] Source: Yahoo! Finance
[8] Source: Zacks
[9] Equals Average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals Mean ([11]) − Mean ([10])
[13] Equals Mean ([11]) Incl. NJR − Mean ([10]) Incl. NJR

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
RISK ASSESSMENT

Company	Jurisdiction/Service	[1] Test Year	[2] Rate Base		[3] Revenue Decoupling		[4] Capital Cost Recovery Mechanism	
Atmos Energy Corporation	Kansas - Gas	Historical		Year End		Partial		Yes
	Kentucky - Gas	Fully Forecast		Average		Partial		Yes
	Louisiana - Gas	Historical		Year End		Partial		Yes
	Mississippi - Gas	Partially Forecast		Average		Partial		Yes
	Tennessee - Gas	Fully Forecast		Average		Partial		No
	Texas - Gas	Historical		Year End		Partial		Yes
Northwest Natural Gas Company	Oregon - Gas	Fully Forecast		Average		Partial		No
	Washington - Gas	Historical		Average		No		No
ONE Gas, Inc.	Kansas - Gas	Historical		Year End		Partial		Yes
	Oklahoma - Gas	Historical		Year End		Partial		No
	Texas - Gas	Historical		Year End		Partial		Yes
South Jersey Industries, Inc.	New Jersey - Gas	Partially Forecast		Year End		Full		Yes
Southwest Gas Corporation	Arizona - Gas	Historical		Year End		Full		Yes
	California - Gas	Fully Forecast		Average		Full		No
	Nevada - Gas	Historical		Year End		Full		Yes
Spire, Inc.	Alabama - Gas	Fully Forecast		Average		Partial		No
	Missouri East - Gas	Historical		Year End		Partial		Yes
	Missouri West - Gas	Historical		Year End		No		Yes
Proxy Group Operating Company Count	Fully Forecast	5	Year End	11	Full	4	Yes	12
	Partially Forecast	2	Average	7	Partial	12	No	6
	Historic	11			No	2		
	Forecast	38.89%	Year End	61.11%	RDM	88.89%	CCRM	66.67%
Montana-Dakota Utilities Co. [5]	North Dakota	Fully Forecast		Average		Partial		No

Notes
[1] Source: S&P Global - Market Intelligence Rate Case History (Past Rate Cases), accessed 5/31/2020
[2] Source: S&P Global - Market Intelligence Rate Case History (Past Rate Cases), accessed 5/31/2020
[3] - [4] Source: "Adjustment Clauses: A State-by-state Overview," Regulatory Research Associates, November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.
[5] Data provided by MDU

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	58.43%	59.20%	58.43%
New Jersey Resources Corporation	NJR	58.87%	61.92%	58.87%
Northwest Natural Gas Company	NWN	49.19%	49.33%	49.19%
One Gas Inc.	OGS	63.55%	62.03%	63.55%
South Jersey Industries, Inc.	SJI	52.88%	52.82%	52.88%
Southwest Gas Corporation	SWX	48.52%	49.38%	48.52%
Spire Inc.	SR	61.80%	62.79%	61.80%
Proxy Group Excluding NJR				
MEAN		55.73%	55.92%	55.73%
LOW		48.52%	49.33%	48.52%
HIGH		63.55%	62.79%	63.55%
Proxy Group Including NJR				
MEAN		56.18%	56.78%	56.18%
LOW		48.52%	49.33%	48.52%
HIGH		63.55%	62.79%	63.55%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	58.43%	59.20%	58.43%
New Jersey Natural Gas Company	NJR	58.87%	61.92%	58.87%
Northwest Natural Gas Company	NWN	49.19%	49.33%	49.19%
Kansas Gas Service Company, Inc.	OGS	63.55%	62.20%	63.55%
Oklahoma Natural Gas Company	OGS		61.94%	61.94%
Texas Gas Service Company, Inc.	OGS		61.95%	61.95%
South Jersey Gas Company	SJI	52.88%	52.82%	52.88%
Southwest Gas Corporation	SWX	48.52%	49.38%	48.52%
Spire Alabama Inc.	SR	66.82%	71.48%	66.82%
Spire Gulf Inc.	SR		45.31%	45.31%
Spire Mississippi Inc.	SR		100.00%	100.00%
Spire Missouri Inc.	SR	59.05%	58.91%	59.05%

Notes:
[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.
[2] Natural Gas operating subsidiaries where data was unable to be obtained for 2018 and 2019 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	41.57%	40.80%	41.57%
New Jersey Resources Corporation	NJR	41.13%	38.08%	41.13%
Northwest Natural Gas Company	NWN	50.81%	50.67%	50.81%
One Gas Inc.	OGS	36.45%	37.97%	36.45%
South Jersey Industries, Inc.	SJI	47.12%	47.18%	47.12%
Southwest Gas Corporation	SWX	51.48%	50.62%	51.48%
Spire Inc.	SR	38.20%	37.21%	38.20%
Proxy Group Excluding NJR				
MEAN		44.27%	44.08%	44.27%
LOW		36.45%	37.21%	36.45%
HIGH		51.48%	50.67%	51.48%
Proxy Group Including NJR				
MEAN		43.82%	43.22%	43.82%
LOW		36.45%	37.21%	36.45%
HIGH		51.48%	50.67%	51.48%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	41.57%	40.80%	41.57%
New Jersey Natural Gas Company	NJR	41.13%	38.08%	41.13%
Northwest Natural Gas Company	NWN	50.81%	50.67%	50.81%
Kansas Gas Service Company, Inc.	OGS	36.45%	37.80%	36.45%
Oklahoma Natural Gas Company	OGS		38.06%	38.06%
Texas Gas Service Company, Inc.	OGS		38.05%	38.05%
South Jersey Gas Company	SJI	47.12%	47.18%	47.12%
Southwest Gas Corporation	SWX	51.48%	50.62%	51.48%
Spire Alabama Inc.	SR	33.18%	28.52%	33.18%
Spire Gulf Inc.	SR		54.69%	54.69%
Spire Mississippi Inc.	SR		0.00%	0.00%
Spire Missouri Inc.	SR	40.95%	41.09%	40.95%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.

[2] Natural Gas operating subsidiaries where data was unable to be obtained for 2018 and 2019 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%
New Jersey Resources Corporation	NJR	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%
One Gas Inc.	OGS	0.00%	0.00%	0.00%
South Jersey Industries, Inc.	SJI	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%
Spire Inc.	SR	0.00%	0.00%	0.00%
Proxy Group Excluding NJR				
MEAN		0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%
Proxy Group Including NJR				
MEAN		0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%
New Jersey Natural Gas Company	NJR	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS		0.00%	0.00%
Texas Gas Service Company, Inc.	OGS		0.00%	0.00%
South Jersey Gas Company	SJI	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	0.00%	0.00%	0.00%
Spire Gulf Inc.	SR		0.00%	0.00%
Spire Mississippi Inc.	SR		0.00%	0.00%
Spire Missouri Inc.	SR	0.00%	0.00%	0.00%

Notes:
[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.
[2] Natural Gas operating subsidiaries where data was unable to be obtained for 2018 and 2019 were removed from the analysis.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-20-___

Direct Testimony
of
Patrick C. Darras

Q. Please state your name and business address.

A. My name is Patrick C. Darras, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Vice President – Engineering & Operations Services for Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company"), Great Plains Natural Gas Co. ("Great Plains"), Cascade Natural Gas Corporation ("Cascade"), and Intermountain Gas Company ("Intermountain").

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

A. I have executive responsibility for the development, coordination, and implementation of Company strategies and policies relative to all areas of engineering and operations including design, construction, compliance, and pipeline integrity and safety.

Q. Please outline your educational and professional background.

A. I am a graduate of North Dakota State University with a Bachelor of Science Degree in Construction Engineering. I also hold an MBA along with a Master's Degree in Management both from the University of Mary. In June of 2014 I attended the Utility Executive Course at the University of Idaho.

I began my career in 2002 as a gas engineer with Montana-Dakota in Bismarck. I held that position for four years primarily working with the construction and service group in day to day operations. In 2006 I was promoted into the role of Region Gas Superintendent where I was responsible for the overall gas engineering, construction, and service of the Dakota Heartland Region of Montana-Dakota. I worked in that capacity for two years and was then promoted to Region Director for Montana-Dakota's Dakota Heartland Region and Great Plains. My responsibility in this role was oversight of all gas and electric operations for the Region. In January 2015, I accepted the promotion to Vice President of Operations for Montana-Dakota and Great Plains. My responsibilities in this role included gas and electric distribution operations and engineering across the five states of Montana, North Dakota, South Dakota, Wyoming, and Minnesota. In June of 2018, I accepted my current role of Vice President – Engineering and Operations Services.

Prior to joining Montana-Dakota, I worked for a local industrial contractor specializing in refinery and power plant maintenance along with turn-key construction of industrial facilities such as refineries and food processing plants. I spent seven years with this group in various capacities in engineering, construction, and project management.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) provide an overview of the Company's project selection and budgeting process; and (2) provide an overview of the Company's major capital projects that have been completed since the last rate case and those currently in progress.

OVERVIEW OF PROJECT SELECTION AND BUDGETING PROCESS

Q. What type of major capital projects does the Company typically perform?

A. The bulk of Montana-Dakota's major capital projects are pipeline replacement projects that have been identified for safety reasons and to reduce risk on Montana-Dakota's system, and system reinforcements or system expansions that have been identified as needed to ensure system reliability and to accommodate growth on the Company's system. A reinforcement is an upgrade to existing infrastructure or new system additions, which increases system capacity, reliability, and safety. An expansion is a new system addition to accommodate an increase in demand. Collectively, these are known as distribution system enhancements. Distribution system enhancements do not reduce demand, nor do they create additional supply. Instead, enhancements can increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The two broad categories of distribution enhancement solutions are pipelines and regulators.

Q. How does the Company identify safety-related projects?

A. The Company uses the Distribution Integrity Management Program ("DIMP") and the expertise of its own engineers and field management to identify areas of risk on its system and to develop the safety projects required to remediate risk. The DIMP supports Montana-Dakota's understanding of the system and material characteristics and is used to identify, assess, and prioritize integrity risks to Company-owned and operated infrastructure. The Company reviews and analyzes the DIMP risk model outputs after each model run to identify areas of highest risk and those areas where risk increased from the last model run.

Additionally, because the DIMP model does not perfectly capture all risk factors, the Company also considers input from its system engineers, local field management, and other subject matter experts ("SMEs") who have detailed knowledge of specific portions of Montana-Dakota's system to identify other areas of potential concern.

The Company then considers and analyzes existing and proposed measures to address the threats to Montana-Dakota's pipeline system. The prioritization and selection of the appropriate remediation actions depends on the type of threat being addressed, whether the threat is current or potential, and the viability of the remedial action in managing the relevant risk factors.

Q. Has the Company done studies outside of the DIMP process regarding pipeline safety-related projects?

A. Yes, Montana-Dakota contracted with GTI to assist in evaluating the remaining useful life expectancy and the corresponding pressure-carrying capacity of various vintages of Aldyl-A pipe material installed in several gas distribution systems operated by Montana-Dakota. While the study is still ongoing, initial results indicate that the samples taken to date show that the pipe looks very good for the decades it has been in service. The current results; however, do not imply that the pipe is perfect and laboratory testing has concluded that the pipe is trending downward in performance. At this time, the System Integrity Department does not see the need to make adjustments to the DIMP model or base replacement projects solely on Aldyl-A presence. The System Safety and Integrity Program (SSIP) continues to prioritize replacement and elimination of early vintage plastic pipelines prone to poor manufacturing, industry documented Aldyl-A plastic defects, unknown attributes, missing data, mechanical fittings, inside gas meters, and non-reported third party damages.

Q. What types of projects are typically performed to address safety-related concerns?

A. Pipeline replacement is typically the most viable option to remediate risks associated with material, joint, weld, corrosion, natural forces, and/or equipment. If Montana-Dakota determines that replacement is an appropriate action to reduce the risk, the Company establishes a replacement project.

Q. How does the Company prioritize and select safety-related projects?

A. Once pipe segments requiring replacements have been identified, the Company plans and prioritizes specific projects within these segments. This process ensures that higher risk threats are mitigated in a timely manner.

Q. Please provide an overview of Montana-Dakota's capital budgeting process.

A. Capital additions and changes are planned through the annual budget process using PowerPlan (PP). The budget process begins with an individual (originator) creating specific funding projects in PP for all new projects to be included in the five-year capital budget. Originators are generally managers at the district level or engineering staff at the corporate level. Sources of information for capital projects include the DIMP, state and local government agencies, and internal Montana-Dakota personnel. Funding projects are used to hold the capital budget estimates and will be linked to the work orders to be created when actual costs commence. A Fixed Asset Financial Analyst reviews the funding projects for proper setup. If the project is not considered a capital expenditure as it was submitted, it is rejected and sent back to the originator for revision, cancelation, or it is moved to Operations and Maintenance (O&M) Expense. After the review has been completed, the Fixed Asset Financial Analyst will add appropriate overheads and approve the funding project.

Blanket funding projects are used year after year to budget for high volume mass property work orders typically under $100,000 each.

Once all the funding projects have been updated with expenditures, various Company operating managers generate reports to show estimated expenditures and justification for each project. The managers perform the review of the funding projects and see if any necessary changes made to the estimate support the project. Reports are then generated by the budgeting personnel for review and approval by the Directors and Vice Presidents of the Utility Group. Any final budget changes are made, and the budgets are then presented to the Utility Group's President for review and approval. The final Utility Group budget is then presented to the MDU Resources CEO for review and approval. If the budget is approved by the MDU Resources CEO, the final review and approval occurs with the Board of Directors. At each stage of the review and approval process a project (or projects) can be challenged for appropriateness and can be removed from the capital budget or moved to another year within the five-year budget. The addition or removal of projects can also be impacted by other factors such as available capital and/or borrowing capacity.

After final approval, an approved budget version is created in PP and locked and the funding projects and estimated amounts in the approved budget version are copied back to the working budget version. Project managers are notified that the budget has been approved and than can create work orders from the funding projects. Projects are monitored and updated throughout the year as part of the review process and to insure, as best as possible, that projects are completed on time and within the approved budget.

Q. Have there been any changes to these processes since the Company's last rate case?

A. Yes. Beginning in January 2019, MDU Utilities Group moved toward a "one utility" model. As a result, the engineering department was reorganized, and more consistent tasks and processes were defined. The engineering managers and directors collaboratively review all projects and determine which are the most important from a risk standpoint and what the timing of the projects should be to best mitigate risks. Within this effort, there is also a new internal requirement to develop a more robust analysis for any project with a cost estimate over $1 million. As part of the analysis, the Company develops documentation supporting the project, including a substantial executive summary, Synergi model snapshots, alternative considerations, and timing and justifications.

Q. For work that will be performed in 2020, does the Company anticipate that its actual investment may vary from the budgeted amounts?

A. The Company's capital budgets were developed in November 2019 and the Company expects that its actual investment will not differ materially from the budgeted amounts for the projects that are not yet complete. Ongoing construction work is still being performed during the

COVID-19 pandemic and Montana-Dakota is not aware of any immediate impacts to the construction schedules for its capital projects.

MAJOR CAPITAL PROJECTS

Q. Would you please describe the major capital projects that have been completed since the last rate case and the projects that are currently underway?

A. Yes. I will provide a description of each project including the need for each project.

Richardton, ND Replacement

Q1. Please describe the Richardton Replacement project.

A. The Richardton, ND SSIP project replaced Early Vintage Plastic Pipe (EVPP) and Early Vintage Steel Pipe (EVSP) natural gas mains and services. The project consisted of approximately 19,600 feet of 2” PE main and 121 service lines.

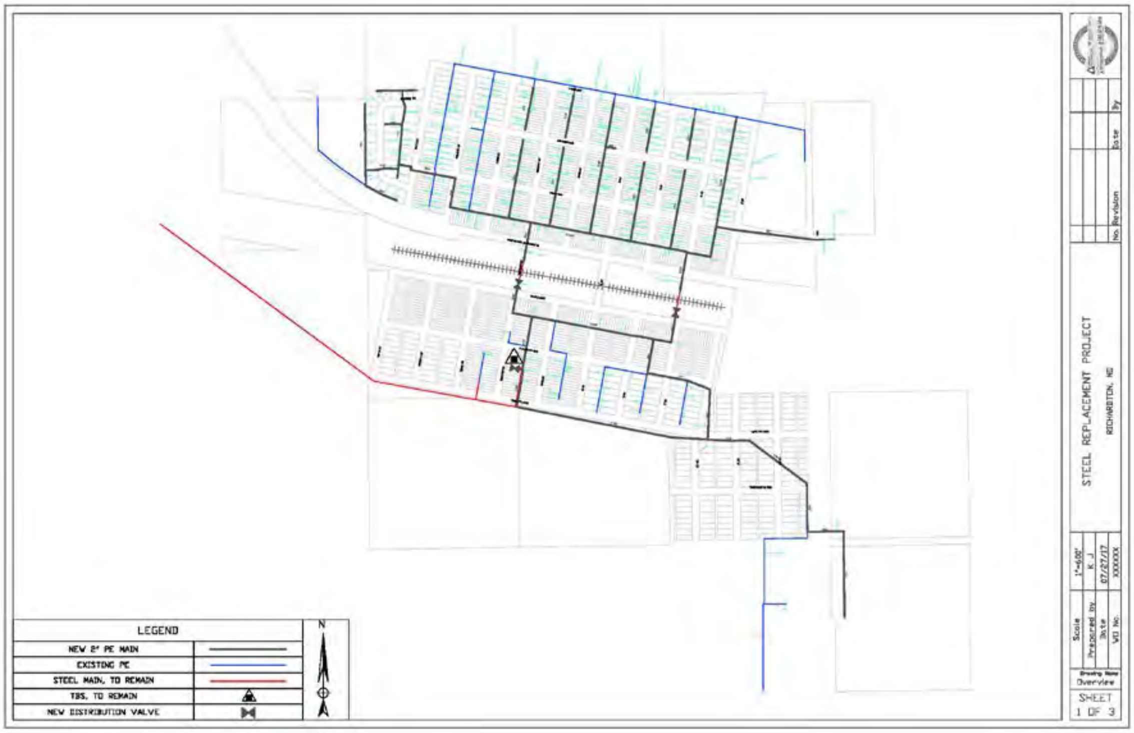


Figure 1 - Richardton, ND

Q2. Why did the Company undertake the Richardton Replacement?

A. Richardton was identified as a high risk EVSP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. This Richardton SSIP project was started and completed in 2017.

Q4. How will the Company's customers benefit from the project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings, inside gas meters, and non-reported third party damages under its SSIP. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVSP category.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Main Replacements - $456,894

Service Replacements - $317,020

Barlow, ND SSIP Replacement

Q1. Please describe the Barlow SSIP Replacement project.

A. The Barlow, ND SSIP project replaced EVPP and EVSP natural gas mains and services. The project consisted of approximately 3,000 feet of 2” PE main and 8 service lines.

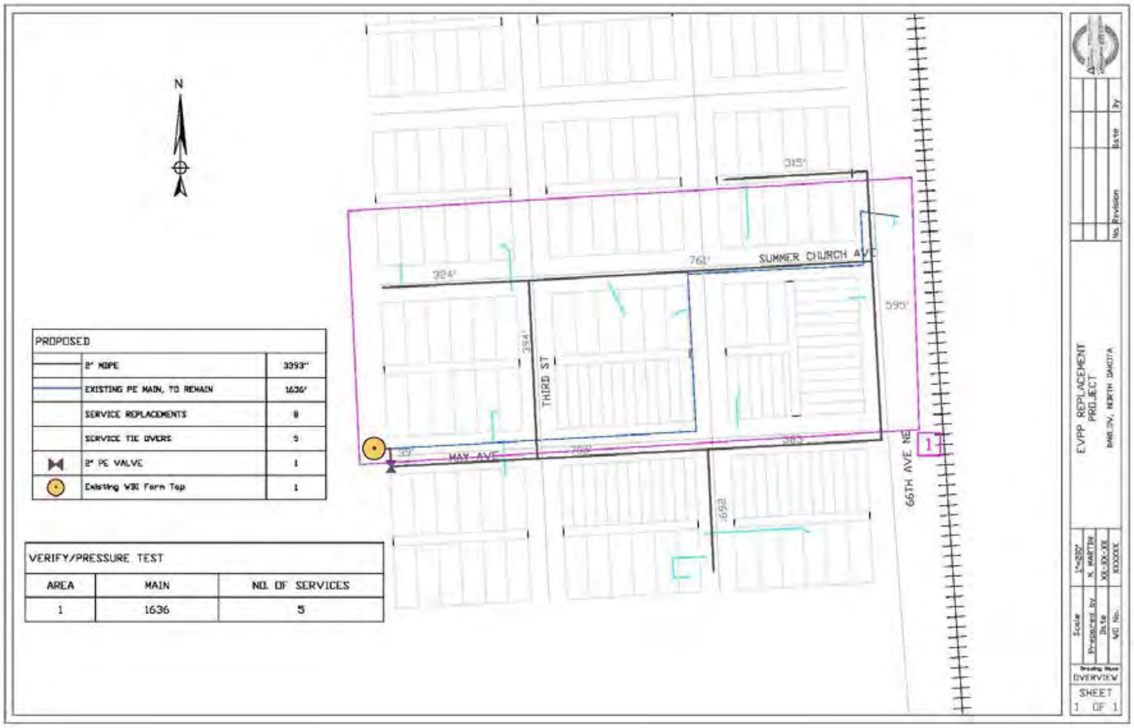


Figure 2 - Barlow, ND

Q2. Why did the Company undertake the Barlow SSIP Replacement?

A. Barlow was identified as a high risk EVPP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. This Barlow SSIP project was started and completed in 2018.

Q4. How will the Company's customers benefit from this SSIP project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings,

inside gas meters, and non-reported third party damages. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVPP category.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Main Replacements - $80,433

Service Replacements - $31,947

Cleveland, ND SSIP Replacement

Q1. Please describe the Cleveland SSIP Replacement.

A. The Cleveland, ND SSIP project replaced EVPP and EVSP natural gas mains and services. The project consisted of approximately 210 feet of 2” PE, 330 feet of 4” PE, 420 feet of 4” steel main, and 2 service lines.

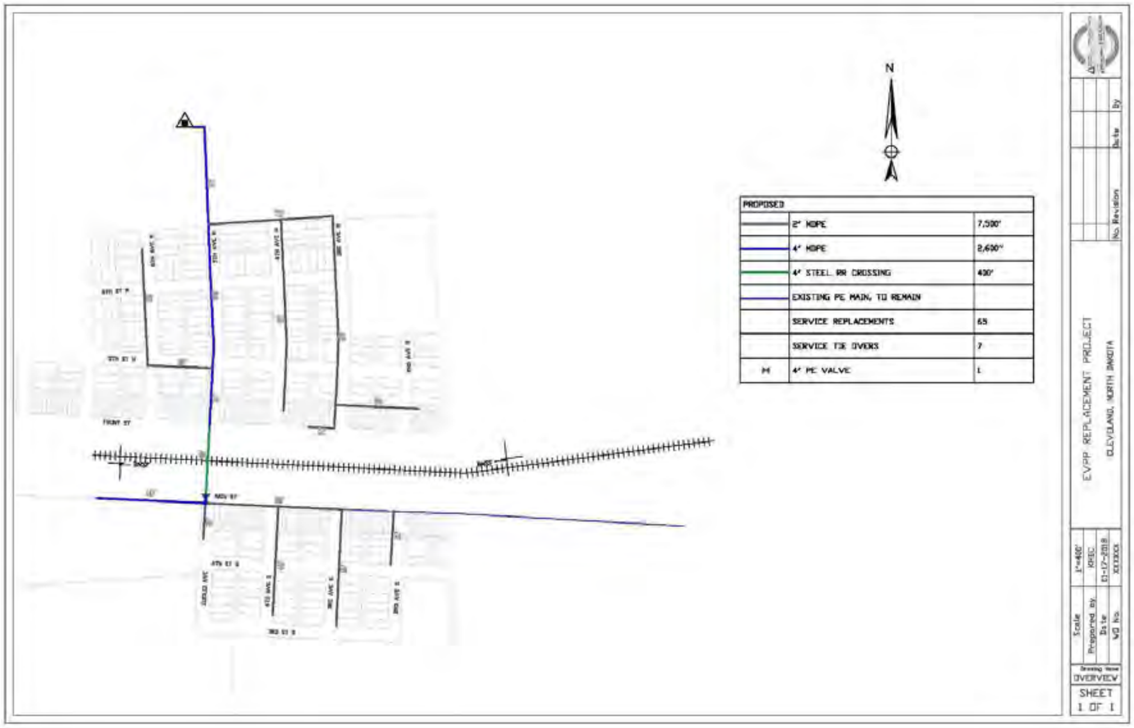


Figure 3 - Cleveland, ND

Q2. Why did the Company undertake the Cleveland SSIP Replacement?

A. Cleveland was identified as a high risk EVPP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. The Cleveland SSIP project was started and completed in 2018.

Q4. How will the Company's customers benefit from this SSIP project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings,

inside gas meters, and non-reported third party damages. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVPP category.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Main Replacements - $54,307

Service Replacements - $9,200

Eldridge, ND SSIP Replacement Project

Q1. Please describe the Eldridge SSIP Replacement.

A. The Eldridge, ND SSIP project replaced EVPP and EVSP natural gas mains and services. The project consisted of approximately 3,000 feet of 2” PE main and 19 service lines.

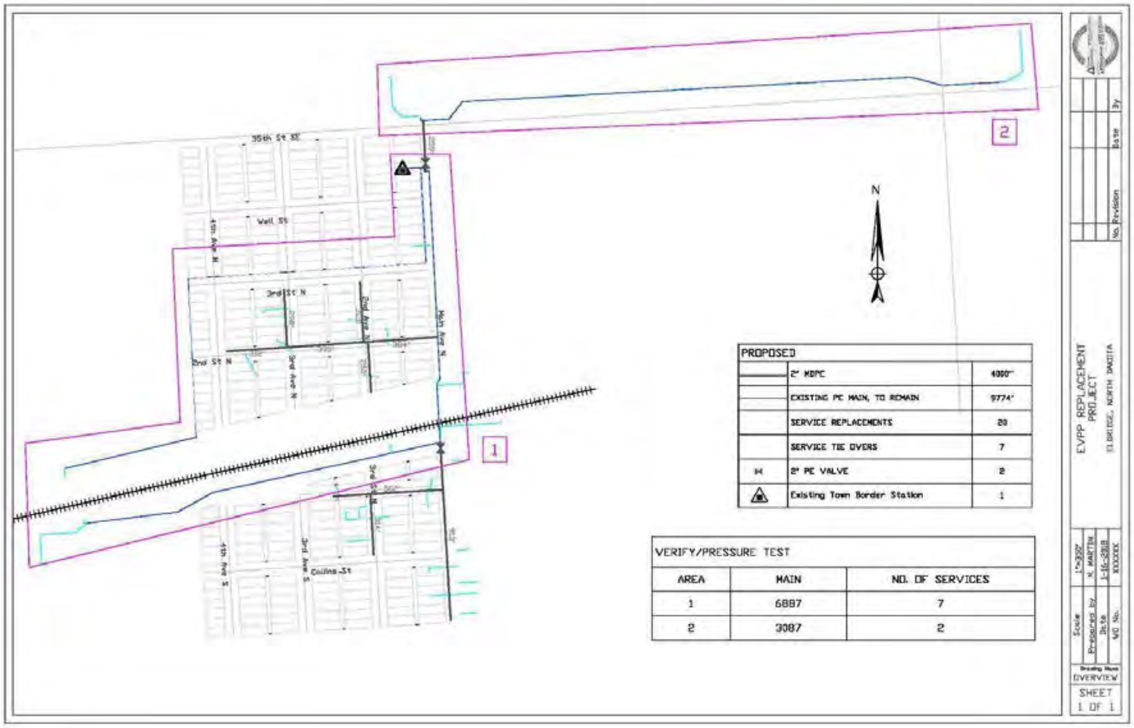


Figure 4- Eldridge, ND

Q2. Why did the Company undertake the Eldridge SSIP Replacement?

A. Eldridge was identified as a high risk EVPP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. The Eldridge SSIP project was started and completed in 2018.

Q4. How will the Company's customers benefit from this SSIP project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings,

inside gas meters, and non-reported third party damages. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVPP category.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Main Replacements - $103,367

Service Replacements - $62,912

Fairview, ND SSIP Replacement Project

Q1. Please describe the Fairview, ND SSIP Replacement.

A. The Fairview, ND SSIP project replaced EVPP and EVSP natural gas mains and services. The project consisted of approximately 16,500 feet of 2-inch PE, 1,250 feet of 4-inch PE, 595 feet of 4-inch steel main, and 53 service lines. The Fairview, ND SSIP was a multi-year project that coincided with the Fairview, MT state replacement plan.

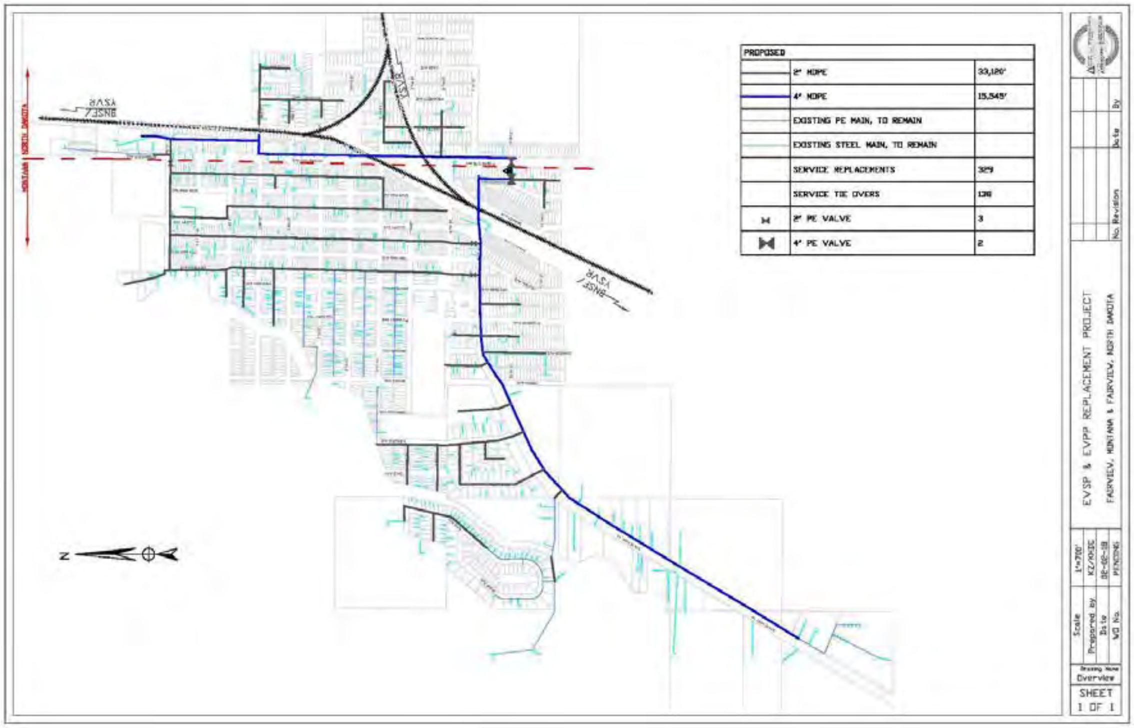


Figure 5 - Fairview, ND

Q2. Why did the Company undertake the Fairview SSIP Replacement?

A. Fairview was identified as a high risk EVSP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. The Fairview SSIP project started in 2018 and completed in 2020.

Q4. How will the Company's customers benefit from this SSIP project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings,

inside gas meters, and non-reported third party damages. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVSP category.

Q6. What are the costs of the project?

A. The cost of the project to date are as follows:

2018 Main Replacements - $92,890

2018 Service Replacements - $22,031

2019 Main Replacements - $298,986

2019 Service Replacements - $164,594

The estimated costs for 2020 are as follows:

2020 Main Replacements - < $15,000

2020 Service Replacements - < $15,000

Taylor, ND SSIP Replacement

Q1. Please describe the Taylor SSIP Replacement project.

A. The Taylor, ND SSIP project replaced EVPP and EVSP natural gas mains and services. The project consisted of approximately 12,700 feet of 2-inch PE main and 61 service lines.

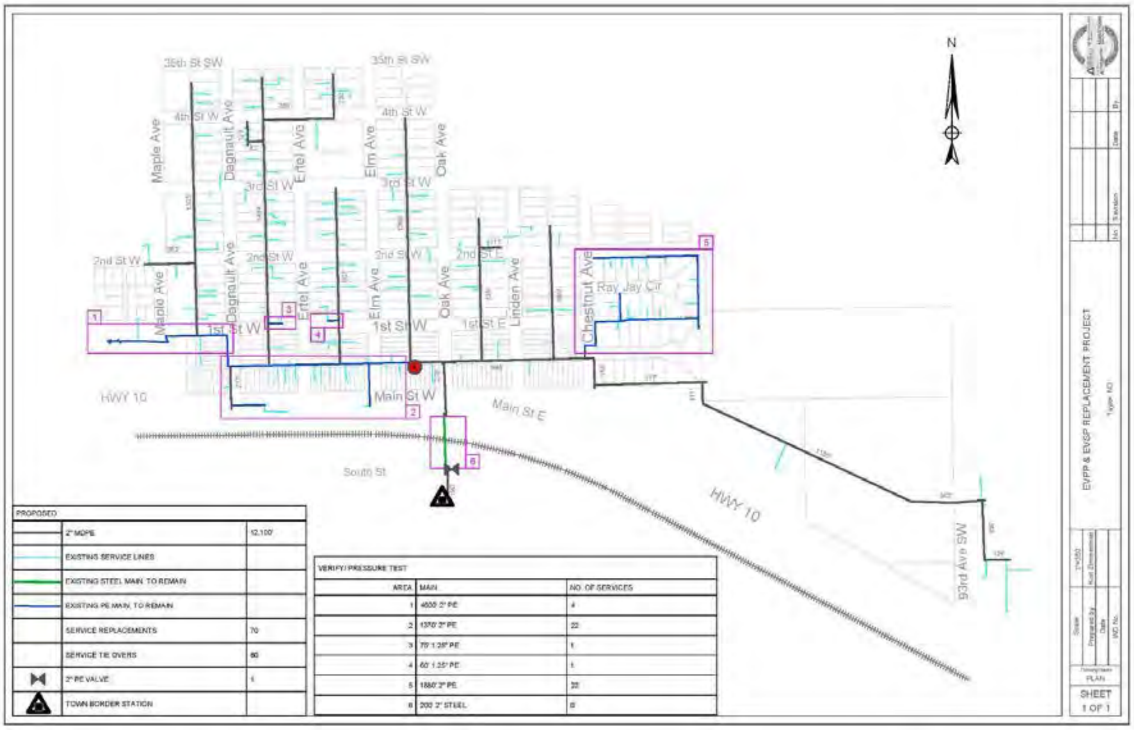


Figure 6 - Taylor, ND

Q2. Why did the Company undertake the Taylor SSIP Replacement?

A. Taylor was identified as a high risk EVSP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. The Taylor SSIP project was started and completed in 2018.

Q4. How will the Company's customers benefit from the project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings,

inside gas meters, and non-reported third party damages. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVSP category.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Main Replacements - $274,088

Service Replacements - $174,329

Gladstone, ND SSIP Replacement

Q1. Please describe the Gladstone SSIP Replacement project.

A. The Gladstone, ND SSIP project replaced EVPP and EVSP natural gas mains and services. The project consisted of approximately 9,000 feet of 2-inch PE main and 56 service lines.

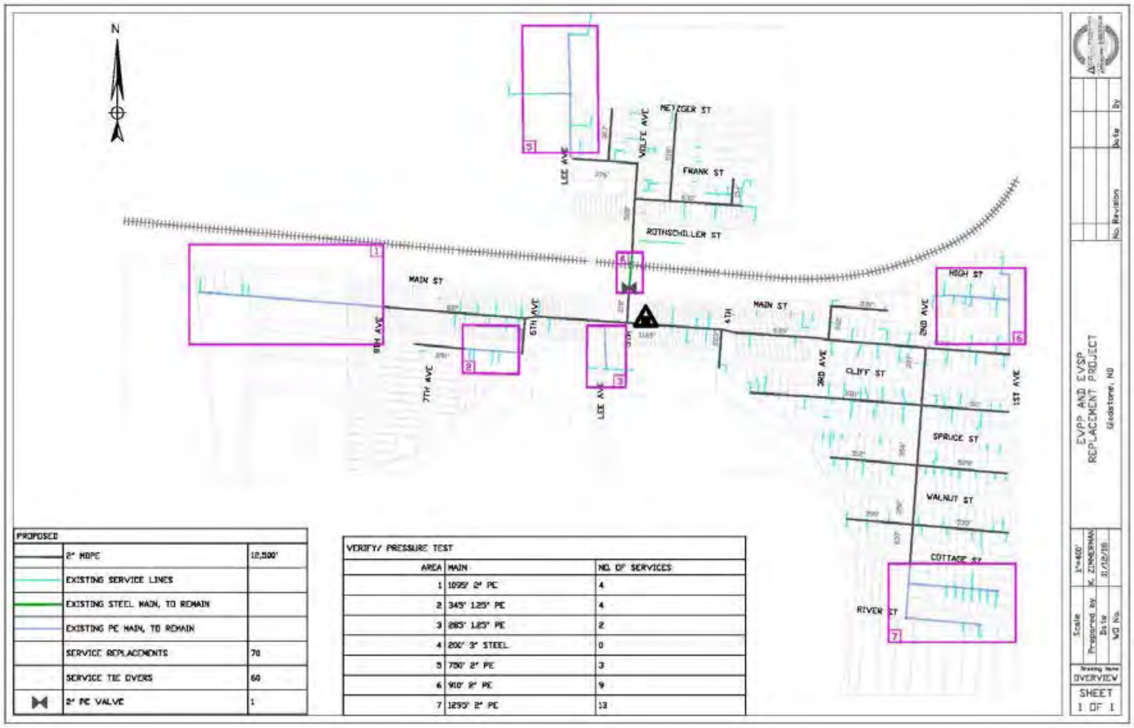


Figure 7 - Gladstone, ND

Q2. Why did the Company undertake the Gladstone SSIP Replacement?

A. Gladstone was identified as a high risk EVSP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. The Gladstone SSIP project was started and completed in 2018.

Q4. How will the Company's customers benefit from the project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings,

inside gas meters, and non-reported third party damages. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVSP category.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Main Replacements - $305,870

Service Replacements - $202,603

Glen Ullin, ND SSIP Replacement Project

Q1. Please describe the Glen Ullin, ND SSIP Replacement.

A. The Glen Ullin, ND SSIP project replaced EVPP and EVSP natural gas mains and services. The project consisted of approximately 28,000 feet of 2-inch PE, over 6,000 feet of 4-inch PE main, 409 service lines.

Figure 8 - Glen Ullin, ND

Q2. Why did the Company undertake the Glen Ullin SSIP Replacement?

A. Glen Ullin was identified as a high risk EVSP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. The Glen Ullin SSIP project was started in 2018 will be completed in 2020.

Q4. How will the Company's customers benefit from this SSIP project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings, inside gas meters, and non-reported third party damages. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVSP category. In addition to the elevated SSIP score, MDU replaced facilities in direct conflict with the City's water, sewer, and storm sewer replacement project

Q6. What are the costs of the project?

A. The cost of the project to date are as follows:

2018 Main Replacements - $916,033

2018 Service Replacements - $697,558

2019 Main Replacements - $156,931

2019 Service Replacements - $134,064

Estimated costs for 2020 are as follows:

2020 Main Replacements - $10,000

2020 Service Replacements - $10,000

New Salem, ND SSIP Replacement Project

Q1. Please describe the New Salem, ND SSIP Replacement.

A. The New Salem, ND SSIP project replaced EVPP and EVSP natural gas mains and services. The project consisted of approximately

29,000 feet of 2-inch PE, 17,000 feet of 4-inch PE, 510 feet of 4" steel main, and 386 service lines.

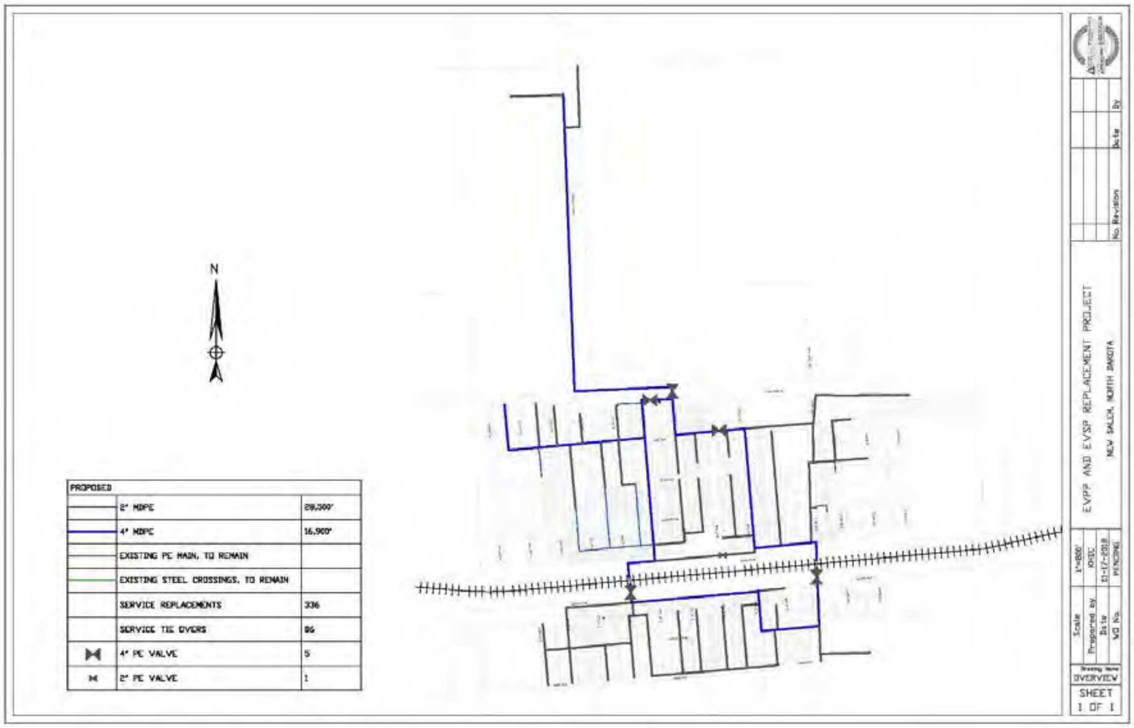


Figure 9 - New Salem, ND

Q2. Why did the Company undertake the New Salem SSIP Replacement?

A. New Salem was identified as a high risk EVSP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. The New Salem SSIP project was started in 2018 and will be completed in 2020.

Q4. How will the Company's customers benefit from this SSIP project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings, inside gas meters, and non-reported third party damages. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVSP category.

Q6. What are the costs of the project?

A. The cost of the project to date are as follows:

2018 Main Replacements - $1,398,650

2018 Service Replacements - $708,109

2019 Main Replacements - $191,481

2019 Service Replacements - $218,772

Estimated costs for 2020 are as follows:

2020 Main Replacements - $20,000

2020 Service Replacements - $20,000

Dickinson, ND SSIP Replacement Project

Q1. Please describe the Dickinson, ND SSIP Replacement.

A. The Dickinson, ND SSIP project replaced EVPP and EVSP natural gas mains and services. The 2019 and 2020 scopes of work are as follows:

	2019	2020
2” PE	20,000	27,000
4” PE	5,000	12,700
6” PE	7,500	100
12” PE		4,100
6” Steel	510	
Service Count	405	567

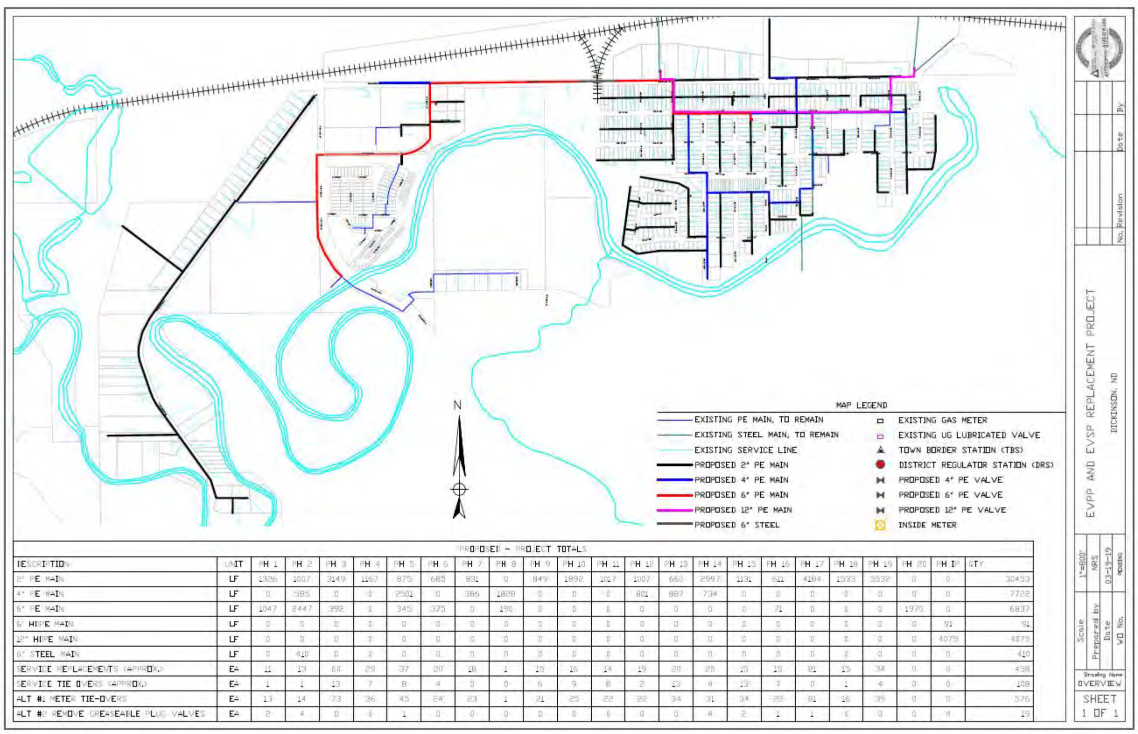


Figure 10 - Dickinson, ND (2019-2020)

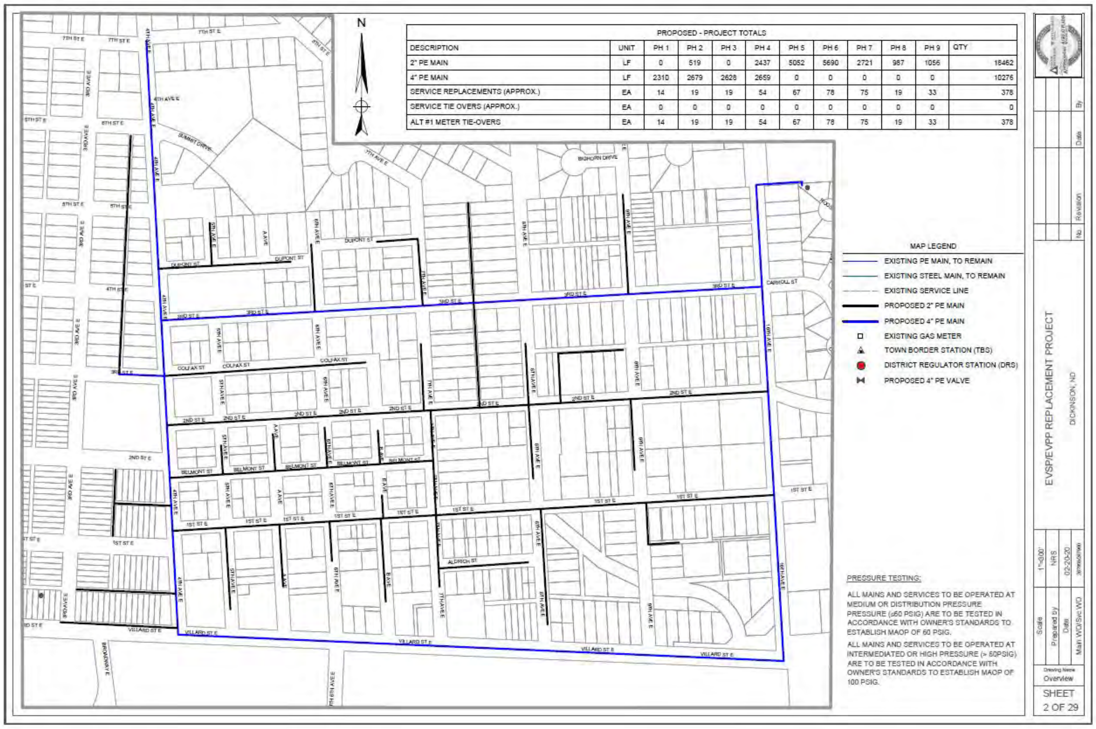


Figure 11 - Dickinson, ND (2020)

Q2. Why did the Company undertake the Dickinson SSIP Replacement?

A. In 2019, Dickinson was identified as a high risk EVSP natural gas system by the Company's SSIP. The SSIP employs structured replacement criteria for EVSP and EVPP. Beginning in 2019, project selection has evolved from utilizing independent high score categories to an integrated, system-based approach which ranks EVSP and EVPP jointly.

Q3. What is the project timeline?

A. The Dickinson SSIP is a multi-year project which started in 2019 and is expected to continue until the system's EVSP and EVPP are replaced or an SSIP plan re-evaluation occurs. To-date annual project scopes have been of similar size to accommodate budgetary limits and contractor availability.

Q4. How will the Company's customers benefit from this SSIP project?

A. The Company replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings, inside gas meters, and non-reported third party damages. The replacement of these facilities ultimately increases overall system safety for the public and increases system reliability for MDU customers.

Q5. Did the Company consider alternative ways to meet the need for this project?

A. No alternative for the project was identified. The system was targeted based on high scores within the EVSP category.

Q6. What are the costs of the project?

A. The cost of the project to date are as follows:

2019 Main Replacements - $2,673,232

2019 Service Replacements - $1,296,415

The approved 2020 budget are as follows:

2020 Main Replacements - $3,885,424

2020 Service Replacements - $3,453,876

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-20-___

Direct Testimony
of
Matthew T. Shoemake

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

A. Yes. My name is Matthew T. Shoemake, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am a Regulatory Analyst in the Regulatory Affairs Department for Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co. (Great Plains), herein referred to collectively as “Company.”

Q. **Would you please describe your duties as a Regulatory Analyst?**

A. I assist in the preparation of the Company’s monthly purchase gas adjustment filings, weather normalization of volumes, assist in monthly fuel cost adjustment filings, and other filings required by state commissions.

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

A. I graduated from Texas A&M University in College Station, Texas with a Bachelor of Science degree in Economics with a minor in Business Administration. I have been in my current position with Montana-Dakota for 4 years. Prior to starting in my current role May of 2016, I was a quality control analyst for Knife River, a subsidiary of MDU Resources, for approximately 8 years.

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

A. Yes. I have previously presented testimony before this Commission, the Public Service Commission of Montana, and the Public Utilities Commission of Minnesota.

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

A. The purpose of my testimony is to present the methodology used by the Company to forecast sales data, including weather normalized volumes, projected volumes and projected customers. The totality of this process and its results are the foundational basis for the underlying projected sales and transportation revenues used in this rate case.

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

A. I am sponsoring the development of the forecasted billing units as presented on Exhibit No. ____ (MTS-1 and MTS-2) and ultimately used in the forecasted revenues on Statement F, Schedule F-1 pages 1 through 37. I am also sponsoring the regression models included in Workpapers Statement F, Schedule F-1 pages 1 through 92.

Q. Would you describe the development of the normalized volumes?

A. Volumes for residential, firm general, propane, the Minot Air Force Base and select interruptible and transportation customers were adjusted to reflect normal weather patterns, where appropriate. Each of the aforementioned customer classes was adjusted separately. Further, the normalization models was separated between Montana-Dakota and Great Plains which I will detail later in my testimony. Billing period sales volumes and customers, by month, were the starting point for the data utilized in the models.

First, customer classes were analyzed to determine whether natural gas usage was associated with heating purposes and therefore correlated with weather input from the Company's Gas Supply Department. The general idea of heat-sensitivity is that some customers will increase the amount of natural gas that they consume as the outside temperature drops. Typically, this increase in consumption is cyclical with the calendar – as fall and winter set in, natural gas volumes sold to customers tend to increase. However, there are certain customers and instances in which colder weather is not correlated with the amount of natural gas consumed – these customers are considered non-heat-sensitive.

All firm service customer classes were determined to be heat-sensitive. Interruptible and transportation customers were analyzed on an individual basis and grouped into heat-sensitive and non-heat-sensitive by each customer class.

Q. How were the normalized volumes calculated for heat-sensitive customers?

A. For customer classes and individual customers that were determined to be heat-sensitive, weather and billing data were incorporated into a model using an Ordinary Least Squares (OLS) regression for each respective class of service. To incorporate seasonal weather patterns, billing period degree days based on a 60-degree day were included as an input in the modeled regressions. Billing data used as inputs in the model were the monthly distinct count of customers and the actual dekatherms of gas consumed. The time period for each customer class in the modeled regressions was 36 months, or 3 years.

The structured equation for the OLS models used for heat-sensitive customers is as follows:

$$y = b_0 + b_1 x_i$$

Where, *y* is the natural gas volumes consumed in a month, b_0 is the daily baseload, b_1 is the use per degree day, and x_i is the number of degree days per month.

Using the results of the regression analysis for residential and firm general service customer classes, the daily baseload use per customer (the intercept of the OLS) was multiplied by the respective number of days in each calendar month to arrive at the monthly baseload use per customer. The use per degree day per customer (the slope of the OLS) was then applied to the normal billing period degree days (based on normal weather for 30 years) to determine the normalized heating use per customer. The Company has historically used 30-year normals for weather normalization purposes and believes that using a 30-year normal weather is most appropriate to capture historical weather trends. The results of each of these equations was then combined by the number of customers in each respective month to determine the normalized usage for the twelve months ended December 31, 2019.

Q. How were the normalized volumes calculated for non-heat-sensitive customers?

A. For customers that were determined to be non-heat-sensitive, simple averages of historical consumption patterns were utilized. These averages are considered to be the normalized volumes for the non-heat-sensitive customers. These averages were calculated at an individual customer level. For most non-heat customers, a 36-month average was calculated (January 2017 – December 2019). In some instances, either a 24-month average was calculated or a customer's per books consumption for the most recent 12 months was used. In these cases, either there was not enough historical data for the customer, or the customer cut in and out of service and using longer periods of consumption was deemed inappropriate.

Q. Was any consideration given to customers which changed rate classes?

A. Yes. The Company analyzed the historical data for interruptible and transportation customers that changed rate classes during the time period in the data. During the time period of 2017 through 2019 there were a number of customers that changed rates under which they took service. In its normalization models and projections, the Company ensured that customers were represented in the rate class in which they are currently billed.

The Company also discussed internally with its field operations and gas supply departments to determine if there were any foreseeable changes to the classifications of its interruptible and transportation customers. Any discussions or agreements with customers to change their service rate or stop service altogether that were known at the time of filing were incorporated within the forecasted sales data.

Q. Were other considerations necessary for customers?

A. Yes, the removal of select customers from Rate 71 was also required. Due to the margin sharing adjustment for Montana-Dakota's grain dryers through the purchased gas adjustment as authorized in Case No. PU-13-803 and maintained in PU-15-90 and PU-17-295, all grain drying customers were removed from the Company's normalized and projected volumes. To further ensure the integrity of the projected volumes, customers that were not active at the end of 2019 were completely removed from the entirety of the underlying data for rate 71.

Q. How were the projected volumes calculated for heat-sensitive customers?

A. The projected volumes were based upon the calculated normalized volumes for each customer class. For the residential and firm general rate classes, the Company applied projected customer growth to the normalized volumes to obtain projected volumes. For other heat-sensitive customers and classes, the projected volumes were set equal to the normalized volumes as calculated and described previously.

Q. How were the projected volumes calculated for non-heat sensitive customers?

A. The projected volumes for these customers were set equal to their normalized volumes.

Q. You previously mentioned calculating volumes and customers independently for Montana-Dakota and Great Plains. Would you describe how this affects the normalization models and projected volumes?

A. As has been described by Ms. Kivisto, Ms. Vesey and Ms. Bosch, Montana-Dakota is proposing to incorporate Wahpeton, North Dakota, currently provided for under the Great Plains North Dakota rate book, into Montana-Dakota’s North Dakota gas rate book. As this relates to the normalization models and projected volumes, it is prudent and necessary to calculate normalized and projected volumes for Wahpeton independently of those calculated for Montana-Dakota. As an example, Wahpeton residential volumes are calculated in a similar manner as those of the rest of North Dakota's residential volumes, but they are calculated independently using only residential customers, volumes and weather data for Wahpeton.

Q. How will the incorporation of Wahpeton into Montana-Dakota affect future models and volumes?

A. The models and volumes will remain separate in future rate cases until said time that the billing phases are converged and separate rate schedules for Wahpeton are no longer necessary. At that time, it is expected that all North Dakota models and projections will be incorporated into a single model for rate case purposes.

Q. Would you describe the weather data utilized in developing weather normalized gas sales?

A. The Company purchases raw daily weather data from DTN. The data utilized in the weather normalizations is the average temperature in degrees Fahrenheit for areas of North Dakota that the Company provides natural gas service in. The daily average temperature is compared to an industry standard 60 (sixty) degrees Fahrenheit and if the temperature is below 60 degrees, the difference is considered the degree day value. For example, if the average daily temperature is 55 for March 1st, then the amount of degree days is 5 (60-55=5). These temperatures are collected from seven regional weather stations in North Dakota (Bismarck, Devils Lake, Dickinson, Jamestown, Minot, Wahpeton and Williston) and the differences for each day are considered calendar degree days. The data from these individual weather stations are then weighted based upon billing period cycles to match up with the Company's meter reads and billing process. These calendar degree days for each respective area are then weighted based upon the amount of historical number of bills that are sent to customers in each respective billing period cycle to calculate a billing period degree day (BPDD) for each of the six regions. For Montana-Dakota, these regional BPDDs are then weighted based upon the historical number of firm customer service points to calculate a system-wide North Dakota BPDD. For Great Plains, the BPDD utilizes only Wahpeton weather information.

Q. Would you describe the methodology used to calculate customer counts?

A. The Company's Customer Care and Billing System (CC&B) was the starting point for the development of the customer counts. A Microsoft Excel file containing the service identification numbers (SA IDs) for each rate class was extracted from CC&B. The method to determine customer counts is a feature in Excel named Distinct Count, which counts the number of unique values. The Count feature in Excel counts the total number of values corresponding to a range of data, regardless if a specific value has multiple entries in the data set. The Distinct Count feature has been utilized by Montana-Dakota and Great Plains to determine its customer counts in previous rate cases as it accounts for adjustments and corrections to customer bills in the CC&B data set.

Q. How were growth rates for customers for the projected years calculated?

A. A 3-year average growth rate for the Residential, Small Firm General and Large Firm General was determined to be representative of the growth expected for the future. For the remaining classes, no growth was used so customer counts were left at their respective levels at the end of 2019. Average growth rates were applied to the year-end 2019 customer counts for each rate to project 2020 and for 2020 to project 2021. The percentage of each rate's respective monthly customer counts for 2019 were applied to each of the total projections for 2020 and 2021 to obtain monthly customer projections that were used to determine projected volumes based on the OLS models.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission
Case No. PU-20-___

Direct Testimony
of

Tara R. Vesey

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

A. Yes. My name is Tara R. Vesey, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota).

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

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

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

A. I graduated from North Dakota State University with a Bachelor of Science degree in Economics. I started my career with Montana-Dakota in 2019 as a Regulatory Affairs Manager. Prior to that I was employed for 13 years by a power cooperative. During that time, I held positions of increasing responsibility, including Contract Administrator, Sales Manager, Transportation Manager, and Manager of Market Operations & Logistics.

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

A. Yes. I have previously presented testimony before the Public Service Commissions of Montana and Wyoming.

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

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

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

A. The purpose of my testimony is to present the North Dakota gas operations per books cost of service for the twelve months ended December 31, 2019 and the projected cost of service for 2020 and 2021. Based on the results, I have prepared the calculation of the revenue deficiency and the calculation of the interim request.

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

A. I am sponsoring Statements A through D, Statement F, Schedule F-2, and Statements G through J, Exhibit No.___(TRV-1), Interim Statements A through D, Statement F, Schedule F-2, and Statements G through J, the interim revenue requirement presented in Exhibit No.___(TRV-2), and the proposed Rate 89 – Cost of Gas presented in Appendix B of the Application.

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

A. Yes, they were.

<u>Combining Montana-Dakota and Great Plains North Dakota Operations</u>

Q. Why is this filing inclusive of both Montana-Dakota and Great Plains Natural Gas Company's (Great Plains) North Dakota Operations?

A. As stated in Ms. Kivisto's testimony, the Company and Commission Staff agreed to begin combining all gas operations within North Dakota for reporting purposes in Case Nos. PU-17-490 and PU-17-075. This was seen as a first step to having one North Dakota gas utility operation. This singular operation has thus been reflected in the 2018 and 2019 Annual Report fillings. The Company is proposing to phase in Great Plains' North Dakota customers to become Montana-Dakota customers as a part of this filing. Specific details related to the phases is covered in the testimony of Ms. Bosch.

Q. How has the Montana-Dakota and Great Plains information been combined in the determination of the revenue requirement?

A. The per books information in the cost of service study is the combination of data from Montana-Dakota and Great Plains. This information was then used to project revenue, expense and rate base information that is inclusive of both companies.

Gwinner Pipeline

Q. How has the Company accounted for the Gwinner pipeline?

A. The Gwinner pipeline has been excluded from the Revenue as well as the Rate Base for 2020 and 2021. The revenue associated with this pipeline is collected under a separate, multiyear contract that is filed with this Commission. For this reason, the projected plant associated with the Gwinner pipeline is also excluded from the rate base.

Revenue Requirement

Q. Are any impacts of the COVID-19 pandemic in the projected test period?

A. No, the Company has developed the 2021 test period revenues and expenses based on a 2019 base period. Montana-Dakota has identified several revenue and expense categories that have been impacted during 2020. Examples include, but are not limited to, PPE related costs, computer related costs, vehicles, waived late fees, short term debt issuance, incremental short term debt interest expense, and bad debt expense, which may be somewhat offset by cost savings associated with employee travel and training. However, the rates resulting from this rate case are intended to be used for a number of years beginning in 2021 and the Company expects that its revenues and expenses will be in line with those presented here and will be similar to pre-pandemic levels.

The Company has filed to request a deferred accounting order to account for the revenues and expenses noted above in Case No. Pu-20-219. In the event that the net costs are material, Montana-Dakota will determine the appropriate action at that time.

Q. What were the results of North Dakota gas operations for 2019?

A. Statement A, pages 2 and 3 show the per books income statement and rate base for the total Company and North Dakota gas operations for 2019. As shown on page 2, North Dakota gas operations produced a return on rate base of 5.567 percent for the twelve months ended

December 31, 2019. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the referenced Statements.

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

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense, and rate base to the jurisdictions as part of the regular accounting process on a monthly basis. The allocation methods and procedures are the same as those that have previously been used in Commission proceedings and are based on the principle of assigning and/or allocating costs to the cost causer.

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

A. The revenue requirement is based on a projected average 2021 test period. As stated by Ms. Kivisto, the primary reason for the increase in rates is the increased investment in distribution facilities to ensure system safety and reliability.

Montana-Dakota is using a future test year in accordance with North Dakota Century Code §49-05-04.1.

Q. Would you describe the development of the projected cost of service for 2020 and 2021?

A. The projected 2020 and 2021 cost of service is presented in Statement A, with schedules supporting the income statement in Statements F, G, H, I, and J. The revenues and expenses reflect the annual level that is projected for 2020 and 2021. Likewise, the rate base reflects average 2020 and 2021 plant and related balances.

<u>Income Statement</u>

Q. Would you describe the development of the projected revenues and expenses?

A. The projected revenues for 2020 and 2021 are summarized on Statement F. Mr. Shoemake discusses the development of the projected volumes in his testimony, and Ms. Bosch discusses the development of the sales and transportation revenues in her testimony.

As noted earlier in my testimony, contract revenue related to the Gwinner pipeline has been excluded in the 2020 and 2021 projections as it is collected under a separate, multiyear contract that is filed with this Commission. The associated rate base has also been removed from the revenue requirement.

Other operating revenues are projected to decrease form the 2019 level as shown on Statement F, Schedule F-2, page1, primarily due to the 2019 updated revenue requirement for the Heskett pipeline.

Rent from Property was increased to reflect annualized actual activity in 2020 through the month of May.

Other Revenue was adjusted to reflect an updated revenue requirement for the Heskett pipeline. Late payment and penalty revenues were also adjusted. Late payment revenues were projected for 2020 and 2021 based on the 2019 ratio of late payment revenue to billed sales and transportation revenue of 0.11 percent applied to projected 2020 and 2021 sales and transportation revenue. The 2020 and 2021 penalty revenues were restated to a three-year average for 2017 to 2019 to smooth out year to year fluctuations.

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

A. Yes. The projected 2020 and 2021 operation and maintenance (O&M) expenses are summarized on Statement G, Schedule G-1, pages 1 through 6, with the detail provided on pages 7 through 23.

The cost of gas, shown on page 7, uses the projected sales volumes and the demand cost calculated in the July 2020 demand cost and a projected 2021 annual commodity cost of gas.

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

A. Yes. O&M expenses were reviewed and projected by resource or cost category, some on a North Dakota only basis and some on a total Company basis. Montana-Dakota developed the O&M expenses for 2020 by reviewing current information, as well as discussions with operations personnel to determine the best information for 2020. The projections for 2021 were based on the projected 2020 data. Projected 2021 expenses are based on the Company's best estimate when changes are known or based on an inflation factor when appropriate. To establish an inflation factor, the Company based its factor on the indices published by the Organization for Economic Cooperation and Development, International Monetary Fund, PriceWaterhouseCoopers, and Statistica. The rates are represented in an average of 1.94 percent.

As described above, the Company did not include COVID-19 related expenses in the 2021 test period.

Q. Would you describe the development of the labor and benefits expense?

A. Yes. Labor expense is shown on Schedule G-1, page 8, with actual labor expense for the twelve months ended December 31, 2019 used as the starting point. The overall projected increase of 1.73 percent in 2020 includes an increase of 3.0 percent for bargaining unit employees pursuant to a negotiated union contract and 4.0 percent for non-bargaining unit employees effective in 2020. Incentive compensation has been adjusted to reflect 11.41% of straight time and vacation. The overall increase for projected 2021 is 3.22 percent and includes an increase of 3.0 percent for bargaining unit employees pursuant to a negotiated union contract and 3.5 percent for non-bargaining unit employees effective in 2021.

Benefits are shown on Schedule G-1, page 9. Benefits expense consists of medical/dental insurance, pension, post-retirement, 401K, and workers compensation. Each of these items was adjusted individually. Medical/dental expense for 2020 and 2021 reflect an increase of 9.0 percent and 7.5 percent, respectively, based on premiums in effect for 2020 and projected premiums for 2021. Pension and post-retirement expense for 2020 and 2021 is based on the 2020 Actuarial Estimate. Projected 401K, workers compensation, and other benefits expense reflected the straight time labor increase of 3.63 percent for 2020 and 3.31

percent for 2021.

Q. Would you describe the other projected O&M expense items

A. Yes. The projected subcontract labor expense (Statement G, Schedule G-1, page 10) for 2020 increased slightly to reflect additional meter expenses associated with the System Safety and Integrity Projects. Subcontract labor expense for 2021 was adjusted to reflect inflation at 1.94 percent based on an average of the four indices described above. Materials expense (Statement G, Schedule G-1, page 11) for 2020 is expected to increase due to anticipated replacement projects in Bismarck, ND and the Dakota Heartland region. The increase projected for 2021 is reflective of the 1.94 percent inflation rate.

Vehicles and work equipment (Statement G, Schedule G-1, page 12) reflects all expenses associated with the Company’s vehicles and equipment, such as backhoes, skid steers and excavators, including the cost of fuel, insurance, maintenance and depreciation expense. The depreciation expense on these items is charged to a clearing account (rather than to depreciation expense), where it is then recorded in O&M expense or capitalized as part of a project as the vehicle or work equipment is used. The projected expense has been updated based on the projected plant and deprecation rates approved in Case No. PU-17-295.

Company consumption (Statement G, Schedule G-1, page 13) is the expense for electric and natural gas consumption in Company buildings. The electric component reflects the volumes at rates reflecting the settlement in Case No. PU-18-089. Although volumes remain constant, the rates associated with 2020 decreased as they reflected the July 2020 Fuel and Purchased Power Adjustment. The 2020 rates and volumes are projected to remain at the same level for 2021. The natural gas component is also decreased to reflect normalized volumes and lower gas prices at current rates for 2020. It is projected to remain at that same level for 2021.

Uncollectible accounts expense (Statement G, Schedule G-1, page

14) is based on the ratio of the three-year average of net write-offs to sales and transportation revenue. This ratio was then applied to the projected 2020 and 2021 sales and transportation revenues, which results in an increase in uncollectible accounts.

Projected postage expense (Statement G, Schedule G-1, page 15) for 2020 reflects the number of customers receiving their monthly billing via electronic format as of the December 2019 level adjusting for the additional postage savings for the entire year. Postage expense for 2021 is projected to increase by the 1.94 percent inflation rate.

Software maintenance (Statement G, Schedule G-1, page 16) was adjusted to reflect the current levels for 2020 and the projected expenses for 2021.

Projected building rental expense (Statement G, Schedule G-1, page 17) for 2020 has been adjusted to reflect the annualized current level of expense. The projected 2021 building rental expense reflects an inflation rate of 1.94 percent based on the average of the four indices.

Advertising expense is shown on Statement G, Schedule G-1, page 18. Promotional advertising expense has been eliminated from the projected time periods and informational and institutional advertising are adjusted to exclude advertising that is not applicable to North Dakota gas operations. Additionally, 2021 reflects an inflation rate of 1.94 percent based on the average of the four indices.

Industry dues, (Statement G, Schedule G-1, pages 19 and 20) reflect the projected levels of industry dues. The dues not specifically applicable to North Dakota natural gas operations have been eliminated.

Insurance expense reflects the current insurance level for 2020 and an increase of 3.0 percent for 2021 based on recent trends.

Regulatory commission expense, as shown on page 22 of Statement G, Schedule G-1, reflects the expenses to be incurred in this filing, amortized over a three-year period, and a three-year average of ongoing regulatory commission expense. In addition, it includes the expenses related to the Common and Gas depreciation studies amortized over five years.

The items adjusted individually above represent approximately 97.5 percent of total North Dakota gas O&M expenses, as shown on Statement G, Schedule G-1, pages 5 and 6. The remaining items, which make up approximately 2.5 percent of other O&M expense, were adjusted by 1.94 percent to reflect the effects of inflation for 2020 and 2021.

Q. Would you describe the calculation of depreciation expense?

A. Yes. Projected depreciation expense is summarized on Statement H, page 1. The calculation of depreciation expense and associated accumulated reserve for depreciation is shown on Schedule H-2, pages 1 and 2. The depreciation rates in this filing are consistent with depreciation rates approved in the most recent gas rate case in Case No. PU-17-295. The summary of composite depreciation rates is shown on Statement H, Schedule H-1, page 1.

Q. **How were taxes other than income projected?**

A. Projected taxes other than income are shown in Statement I. Ad valorem taxes were calculated using the projected 2020 and 2021 average plant in service balances and applying the effective tax rate based on the ratio of 2019 ad valorem taxes to average plant balances as of December 31, 2019 by function.

Projected payroll taxes were based on the ratio of payroll taxes to labor expense for 2019 and applied to the projected 2020 and 2021 labor expense to determine the projected payroll taxes.

All other taxes other than income were projected to remain at the 2019 level.

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

A. The projected income tax calculation for North Dakota gas operations is shown in Statement J. Interest is deductible for tax purposes and the projected interest expense, shown on Schedule J-1, page 1, is calculated on the projected rate base using the projected debt ratio and weighted cost of debt from Statement E, page 1.

Excess deferred income taxes are also factored into the projected income taxes for 2020 and 2021 (see Statement J, Schedule J-2, page 1). Non plant excess deferred taxes utilized a 3-year amortization schedule from 2018 to 2020. Therefore, the test period of 2021 no longer reflects non plant excess deferred taxes. Plant related excess deferred taxes are amortized using the average rate assumption method (ARAM) and is reflected in 2020 and 2021. Finally, the amortization of excess deferred income taxes created by the Tax Act of 1986 will be fully amortized in 2021.

North Dakota federal and state income taxes are fully normalized, so the calculation of income taxes is made on the taxable income after interest, since any tax deductions would be fully offset by deferred income taxes.

Rate Base

Q. Would you describe the development of the projected rate base for 2020 and 2021?

A. The rate base is summarized on Statement A, page 3 and shows the 2019 actual and projected 2020 and 2021 rate base for North Dakota gas operations. Statements B, C, D, and J are the supporting components of the projected rate base.

Statement B, page 1 shows the projected plant in service for 2020 and 2021. The projected plant was developed by adding the capital budget items for 2020 to the 2019 plant in service balances, excluding the balance associated with the Gwinner pipeline. The projected plant is detailed in Statement B, Schedule B-1, page 1. Retirements, based on a three-year average of retirements by function, were deducted and the average 2020 balance was calculated. The process was repeated for 2021. Statement B, Schedule B-1, pages 2 through 4 detail the average

Plant in Service associated with the North Dakota gas operations and the Gwinner pipeline. The revenue requirement for the Gwinner pipeline is met via a contract that is filed with this Commission and thus has been excluded from the rate base.

The detailed capital additions by project for 2020 and 2021 are shown on Schedule B-2, pages 1 through 8.

The projected accumulated reserve for depreciation is summarized in Statement C. The projected reserve balances were calculated using the reserve balances at December 31, 2019 (exclusive of the Gwinner pipeline), adding the calculated depreciation expense and deducting retirements based on a three-year average of retirements, as shown on Statement H, Schedule H-2, pages 1 and 2. The average 2020 balances were then calculated and the process was repeated for 2021.

Q. How were the working capital items derived?

A. The projected working capital summary is shown on Statement D, page 1. Detailed information is shown on Schedule D-1, pages 1 through

11. Materials and supplies and fuel stocks were restated to a thirteen-month average on pages 1 and 2, reflecting actual balances through May 2020 with June through December remaining at the 2019 levels.

Prepayments, which are made up of prepaid insurance, are shown on Schedule D-1 page 3. Prepayments are restated to a thirteen-month average balance, reflecting balances through May 2020. The June 2020 through December 2021 balances are based on the projected 2020 and 2021 insurance expense.

The Company is proposing that the Great Plains charges associated with gas in underground storage and prepaid commodity be recovered through a new Montana-Dakota Cost of Gas (COG) – Natural Gas Rate 89 tariff, similar to Montana-Dakota's COG process. The proposed tariff language is included in Appendix B.

Great Plains will continue to be part of the same gas systems that serves Great Plains' Minnesota operations. Wahpeton's cost of gas will remain consistent with the current process with the exception of removing the gas in underground storage and prepaid commodity from rate base and including it as a component of the cost of gas similar to Montana-Dakota's process. The projected impact on the COG is reflected in the following table:

	Gas in Underground	Prepaid Commodity	Total
June	$10,918	$2,365	$13,283
July	21,044	4,717	25,761
August	31,317	7,078	38,395
Septembe	46,872	9,736	56,608
October	50,420	11,734	62,154
November	50,420	11,734	62,154
December	38,256	8,814	47,070
January	26,449	5,926	32,375
February	11,798	2,488	14,286
March	2,612	551	3,163
April	-	-	-
May	-	-	-
June	10,918	2,365	13,283

13 Month	$28,349
Rate of Return	7.304 %
Return	$2,071
Return Requirement	$2,540
Projected	1,085,411
Per dk Charge	$0.002

The unamortized loss on debt was calculated using the balances as of December 31, 2019 and adding the calculated change for 2020, which reflects a reallocation of the balance and the annual amortization, to arrive at a balance for 2020. The 2019 and 2020 balances were then averaged to reflect the 2020 average. The process was repeated to calculate the 2021 average, as shown on Schedule D-1, page 6. The associated accumulated deferred income taxes were also included.

The unamortized redemption of preferred stock cost was calculated using the balances as of December 31, 2019 and adding the calculated change for 2020 to arrive at a balance for 2020. The 2019 and 2020 balances were then averaged to reflect the 2020 average. The process was repeated to calculate the 2021 average, as shown on Schedule D-1, page 7.

The loss on the sale of buildings is reflected on Schedule D-1, page 8. The loss is being amortized over a 20-year period. The projected activity for 2020 is reflected and the 2019 and 2020 balances were then averaged to reflect the 2020 average balance. The process was repeated to calculate the 2021 average balance. The associated accumulated deferred income taxes are also included on page 8.

The Company is proposing to include the provision for post retirement & provision for pensions and benefits in the revenue requirement for the 2021 test period as discussed in the testimony of Ms. Kivisto and Mr. Jacobson.

Customer advances for construction are shown on Schedule D-1, page 11 and have been restated to a thirteen-month average balance for 2020 and 2021, with actuals through May 2020. The associated accumulated deferred income taxes are also included on page 11.

Q. Would you describe how the accumulated deferred income tax balances were developed?

A. The accumulated deferred income tax balances are summarized on Statement J, Schedule J-2, page 1. The projected balances were derived by adding the changes to the deferred income taxes for 2020 and 2021 to the 2019 balances and calculating the average balance.

The changes associated with book/tax depreciation differences (liberalized depreciation, excess plant deferred income taxes, full normalization, and excess deferred taxes – non-plant) are on Schedule J-2, page 1 and display the projected changes due to the plant additions as well as existing plant. The Company is required to use the Proration Method of computing deferred taxes for all test period filings in which a forecast has been used to develop the revenue requirement to comply with IRS normalization rules. As previously mentioned, non plant excess deferred taxes utilized a 3-year amortization schedule from 2018 to 2020 and are no longer in the test period of 2021. Plant related excess deferred taxes are amortized using the average rate assumption method (ARAM) and is reflected in 2020 and 2021, and the amortization of excess deferred income taxes created by the Tax Act of 1986 will be fully amortized in 2021.

The accumulated deferred income taxes associated with the unamortized loss on debt, the loss the sale of buildings, the provision for pensions & benefits, the provision for post retirement and customer advances are shown on Statement D, Schedule D-1, pages 6, 8, 9, 10 and 11, respectively. The change in accumulated deferred income taxes associated with the acquisition adjustment are the same as experienced in 2019.

Q. What is the additional revenue requirement calculated on Exhibit No.____(TRV-1)?

A. Exhibit No.____(TRV-1), which is identical to Statement A, page 1, shows the calculation of the revenue deficiency of $8,972,424 based on the projected 2021 income and rate base and using the overall rate of return of 7.304 percent from Statement E, page 1 and supported by Ms. Nygard.

Interim Revenue Requirement

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

A. Yes, it is. As stated by Ms. Kivisto, Montana-Dakota is seeking an interim rate relief in this case pursuant to North Dakota §49-05-06. However, the Company is requested a January 1, 2021 implementation date due to COVID-19

Q. What amount of interim rate relief is the Company seeking?

A. The Company has identified an interim revenue requirement, presented in Exhibit No. ___ (TRV-2) of $6,893,176 and Statement A of the Interim Application based on the 2021 projected cost of service.

Q. Would you please describe the variances of the interim increases from the case?

A. The following items are the primary changes from the Company's general rate case filing:

- The Return on Equity (ROE) was modified to reflect the 9.4 percent authorized in Cases No. PU-17-295 and PU-17-490;
- The balance in the Pension & Benefits and Post Retirement regulatory asset was excluded; and

- Regulatory Commission Expense was adjusted to reflect the rate case expense approved in the Case No. PU-17-295.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
PROJECTED 2021

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$112,506,332	**$8,972,424**		$121,478,756
Transportation	2,242,323			2,242,323
Other	3,472,064			3,472,064
Total Revenues	118,220,719	8,972,424		127,193,143
Operating Expenses				
Operation and Maintenance				
Cost of Gas	73,319,285			73,319,285
Other O&M	23,968,702			23,968,702
Total O&M	97,287,987			97,287,987
Depreciation	11,543,996			11,543,996
Taxes Other Than Income	2,710,719			2,710,719
Income Taxes	(27,247)	2,189,711	2/	2,162,464
Total Expenses	111,515,455	2,189,711		113,705,166
Operating Income	$6,705,264	$6,782,713		$13,487,977
Rate Base	$184,665,625			$184,665,625
Rate of Return	**3.631%**			**7.304%**

1/ Statement A, Page 2.
2/ Reflects state and federal taxes at 24.4049%.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS - INTERIM
PROJECTED 2021

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$112,506,332	**$6,893,176**		$119,399,508
Transportation	2,242,323			2,242,323
Other	3,472,064			3,472,064
Total Revenues	118,220,719	6,893,176		125,113,895
Operating Expenses				
Operation and Maintenance				
Cost of Gas	73,319,285			73,319,285
Other O&M	23,916,665			23,916,665
Total O&M	97,235,950			97,235,950
Depreciation	11,543,996			11,543,996
Taxes Other Than Income	2,710,719			2,710,719
Income Taxes	51,215	1,682,273	2/	1,733,488
Total Expenses	111,541,880	1,682,273		113,224,153
Operating Income	$6,678,839	$5,210,903		$11,889,742
Rate Base	$172,265,168			$172,265,168
Rate of Return	**3.877%**			**6.902%**

1/ Statement A, Page 2.
2/ Reflects state and federal taxes at 24.4049%.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-20-___

Direct Testimony
of
Travis R. Jacobson

Q. Please state your name and business address.

A. My name is Travis R. Jacobson and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and what is your position?

A. I am the Director of Regulatory Affairs for Montana-Dakota Utilities Co. (Montana-Dakota).

Q. Would you please describe your duties as Director of Regulatory Affairs?

A. I am responsible for the development and implementation of Company objectives and policies with respect to rate structure, pricing policies, cost of service studies, fuel cost adjustments, purchased gas cost adjustments and gas tracking adjustments in each of the jurisdictions in which Montana-Dakota operates.

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

A. I graduated from Minot State University with a Bachelor of Science degree in Accounting and I am a Certified Public Accountant (CPA). In June 2019, I completed the Utility Executive Course at the University of Idaho in Moscow, Idaho. I started my career with Montana-Dakota in 1999 as a financial analyst in the Financial Reporting area and during my tenure with the Company have held positions of increasing responsibility, including Supervisor, Financial Reporting & Planning and Manager, Financial Reporting & Planning and Manager, Regulatory Affairs before attaining my current position.

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

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

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

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

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

A. The purpose of my testimony is to present the overall cost of service for the twelve months ended December 31, 2019, the projected cost of service for 2020 and 2021 (test year) and the calculation of the revenue deficiency. I will discuss the Company's proposal to include pension and post retirement benefits regulatory assets in rate base. I will provide an overview of the interim revenue deficiency as well.

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

A. I give an overview of the revenue requirement presented in Statement A, which the Overall Cost of Service, and Exhibit No.___(TRJ-1).

Q. Please describe the revenue requirement presented in the Company's Statement A - Overall Cost of Service.

A. Statement A, pages 2 and 3, as presented in Volume II of the Company's Application shows the 2019 per books income statement and rate base for North Dakota's gas operations and shows a return on rate base of 5.567 percent. Also shown are the Projected 2020 and 2021 rates of return of 4.478 percent and 3.631 percent, respectively. The primary driver in the reduction to projected returns is an increase in rate base as well as the operating expenses associated with the increase in rate base, such as depreciation and property taxes. As will be discussed later in my testimony, Montana-Dakota has also proposed to include the pension & benefits and post retirement regulatory assets in rate base, net of deferred income taxes.

The Company's revenue deficiency of $8,972,424 or an approximate increase of 7.8% is necessary to bring the return on rate base to 7.304 percent.

Q. Montana-Dakota has proposed to include the net pension regulatory asset in rate base. Will you explain why?

A. Yes. As discussed in the testimony of Ms. Kivisto, the Company's required contributions to the pension account resulted in a significant prepaid asset and exceeded the amount of pension expense (commonly referred to as FAS 87 or ASC 715 expense) recovered through the revenue requirement. The contributions are tax deductible for Montana-

Dakota and any earnings on those contributions in the pension trust account are not subject to income tax. With that in mind, the contributions help maintain the required funding level and, at the same time, typically result in lower FAS 87 expense.

Post retirement contributions are typically much more closely matched to the annual expense, so the prepaid asset is much smaller. However, Montana-Dakota considers the benefits and the circumstances surrounding the creation of both prepaid assets or liabilities that it is appropriate to include both pension and post retirement similarly.

The table below presents the regulatory asset or liability position for Montana-Dakota beginning in 2004 through the year ended 2019. As shown, Montana-Dakota has made cash contributions in the amount of $81.5 million but has recovered only $29.4 million through the inclusion of pension expense in the revenue requirement. North Dakota gas operations' share of the total pension regulatory asset is $14.8 million as of December 31, 2019.

	Cash Contributions	Pension Expense	Pension Balance Debit (Credit)
Beginning Balance - 12/31/2004			$7,777,266
Activity - 2005	$0	$4,179,348	3,597,918
Activity - 2006	-	4,118,976	(521,058)
Activity - 2007	1,188,690	3,724,426	(3,056,794)
Activity - 2008	-	2,825,775	(5,882,569)
Activity - 2009	8,347,434	4,759,097	(2,294,232)
Activity - 2010	3,871,657	(5,328)	1,582,753
Activity - 2011	13,757,133	1,610,332	13,729,554
Activity - 2012	12,038,687	(740,118)	26,508,359
Activity - 2013	10,014,592	1,830,351	34,692,600
Activity - 2014	12,202,457	594,340	46,300,717
Activity - 2015	2,182,143	1,398,780	47,084,080
Activity - 2016	-	1,746,833	45,337,247
Activity - 2017	422,015	1,422,159	44,337,103
Activity - 2018	7,200,692	720,403	50,817,392
MDU R funding	(5,133,171)	-	45,684,221
Activity - 2019	15,452,375	1,379,116	59,757,480
Total Funding	$81,544,704	$29,564,490	
Ending Balance - 12/31/2019			$ 59,757,480

Q. Is Montana-Dakota required to make contributions to its pension trust fund? And, what are the ramification if funding is not maintained?

A. Yes. Internal Revenue Service rules govern minimum required pension funding contributions. If required contributions are missed or delayed, the missed payment would be considered a reportable event under the Employee Retirement Income Security Act of 1974 (ERISA) rules. This could also subject the company to excise taxes for failure to meet minimum funding requirements. In addition, if the funded status drops below certain levels, restrictions on benefit payments may be required as well as potentially increased premiums payable to the Pension Benefit Guaranty Corporation.

Q. Montana-Dakota has included pension and post-retirement benefits in this filing. Will you explain why the Company has decided to include these regulatory in rate base at this time?

A. Yes. Montana-Dakota has not previously included the pension & benefits or post-retirement benefits regulatory assets in rate base. As reflected in the table above, the pension regulatory asset fluctuates from an asset to a liability and then, beginning in 2012, started to increase to a magnitude as the Company had made significant funding contributions. However, the amount recovered through the revenue requirement (i.e. recovery of FAS 87 expense as a component of operating expenses) has decreased to the point that the regulatory asset has become a material asset upon which Montana-Dakota is not able to earn a return.

Post retirement benefits regulatory asset is similar in nature, as mentioned earlier, but is on a smaller scale.

Q. Please describe Exhibit No.__(TRJ-1).

A. Exhibit No.__(TRJ-1) was prepared to present the Company's general ledger treatment and to provide a historic view of the pension regulatory asset and liability balances.

Q. Has Montana-Dakota included a request for interim rate relief?

A. Yes. An interim rate relief request of $6,893,176, a 6.0 percent increase, has been developed in a separate set of Interim Statements pursuant to the North Dakota Century Code 49-05-06.

The following items are the primary changes from the Company's general rate case filing:

- The Return on Equity (ROE) was modified to reflect the 9.4 percent authorized in Case Nos. PU-17-295 and PU-17-490;
- The balance in the Pension and Benefits and Post Retirement regulatory assets was excluded; and
- Regulatory Commission Expense was adjusted to exclude the costs associated with this case.

Ms. Vesey will provide supporting testimony for the development of the projected income statement and rate base in her testimony.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PENSION & BENEFITS EXHIBIT
2017 - 2019
(000s)

GENERAL LEDGER RECONCILATION

	2017	2018	2019
Fair Value of Net Plan Assets	$192,712	$167,331	$176,548
Benefit Obligation at End of Year	250,889	219,969	206,730
Funded Status - Over (Under)	($58,177)	($52,638)	($30,182)
Regulatory Asset	$102,514	$103,455	$89,939
Net Asset in Rate Base	$44,337	$50,817	$59,757

MONTANA-DAKOTA UTILITIES CO.
PENSION BALANCE SUMMARY
ENDING DECEMBER 31, 2019

	Cash Contributions 1/	Pension Expense 2/	Pension Balance Debit (Credit)
Beginning Balance - 12/31/2004			$7,777,266
Activity - 2005	$0	$4,179,348	3,597,918
Activity - 2006	-	4,118,976	(521,058)
Activity - 2007	1,188,690	3,724,426	(3,056,794)
Activity - 2008	-	2,825,775	(5,882,569)
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Activity - 2016	-	1,746,833	45,337,247
Activity - 2017	422,015	1,422,159	44,337,103
Activity - 2018	7,200,692	720,403	50,817,392
Corporate Reorg. Adj. 3/	(5,133,171)	-	45,684,221
Activity - 2019	15,452,375	1,379,116	59,757,480
Total Funding	$81,544,704	$29,564,490	
Ending Balance - 12/31/2019			$ 59,757,480

1/ Actuarially determined cash payments to the pension trust fund.
2/ Actuarially determined pension expense use in the development of the revenue requirement through rate cases.
3/ Adjustment to reflect the removal of MDU Resources pension funding - cash received by Montana-Dakota due to the 1/1/2019 corporate reorganization in Case No. PU-18-075.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-20-___

Direct Testimony

of

Ronald J. Amen

August 26, 2020

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 17806 NE 109th Court, Redmond, Washington 98052.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

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

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. In serving as an expert witness for Montana-Dakota in this general rate case proceeding, I am working with Black & Veatch Management Consulting, LLC ("Black & Veatch") under a subcontracting arrangement.

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

A. I have over 40 years of experience in the utility industry, the last 23 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing; competitive market analysis; regulatory planning and policy development; resource planning and acquisition; strategic business planning; merger and acquisition analysis; organizational restructuring; new product and service development; and load research studies. I have prepared and presented expert testimony before utility regulatory bodies across North America and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as **Attachment A** to my testimony.

Q. Please summarize your testimony.

A. In my testimony I present Montana-Dakota's Cost of Service Study ("COSS") and discuss its results. I also present the various rate design proposals filed by Montana-Dakota in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation
- Montana-Dakota's COSS
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Montana-Dakota's Rate Design Proposals
- Customer Bill Impacts

Q. Please provide a list of the exhibits and schedules supporting your testimony.

A. I am sponsoring Statement K, Statement L, and the following exhibits:

- Exhibit No.____(RJA-1), Proposed Revenue Allocation
- Exhibit No.____(RJA-2), Rate 60 Residential Bill Comparison
- Exhibit No.____(RJA-3), Wahpeton Transition Phase 1 & 2 Rate Design
- Exhibit No.____(RJA-4), Rate 70 Firm General Service Bill Comparisons, and
- Exhibit No.____(RJA-5), Wahpeton Rate 63 Residential Bill Comparisons.

II. THEORETICAL PRINCIPLES OF COST ALLOCTION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an embedded COSS is a useful tool for determining the allocation of Montana-Dakota 's revenue requirement among its customer classes. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the incremental change in costs associated with a one-unit change in service (or output) provided by the utility. As a result of using an incremental change, capacity additions tend to be lumpy – meaning that they may add more capacity than required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with either growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information per unit of demand, customer, and energy developed in the cost of service study to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds the incremental cost of providing service but is less than stand-alone costs ("SAC"). The logic for this concept is that if customers' prices exceed incremental cost, those customers make a contribution to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

SAC is an important concept for Montana-Dakota because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed SAC for some customers, prices must nevertheless be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a Local Distribution Company's ("LDC's") customers and the particular costs incurred by the utility in serving those customers.

An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

Q. Why are the relationships between customer requirements, load profiles and usage characteristics significant to cost causation?

A. The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate design day peak capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent, they vary with the amount of gas volumes purchased by the Company for its sales service customers.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

Q. **How does one establish the cost and utility service relationships you previously discussed?**

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment"?

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. What prompts the analyst to elect to perform a special study?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. How do you determine whether to directly assign costs to a particular customer or customer class?

A. Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. Were direct assignments of plant made in Montana-Dakota's COSS?

A. Yes. Special studies were performed to determine a portion of the specific distribution plant installed to serve Montana-Dakota's Large Firm General, Small Interruptible, Large Interruptible, and Minot Air Force Base (Minot AFB) customers. The costs related to these facilities from the following plant accounts were directly assigned to the Small Firm General, Small Interruptible, Large Interruptible, and Minot AFB customer classes.

- Account 375 – Structures and Improvements. Direct assignment to Large Firm General (Rate 70), Large Interruptible (Rate 82), and Minot AFB Delivery (Rate 64).

- Account 376 – Mains. Direct assignment to Large Interruptible (Rate 82) and Minot AFB Distribution (Rate 65).
- Account 378 – Measuring & Regulating Equipment – General. Direct assignment to Large Firm General (Rate 70), Small Interruptible Rates (71 & 81), and Large Interruptible (Rate 82).
- Account 379 – Measuring & Regulating Equipment - City Gate. Direct assignment to Minot AFB Delivery (Rate 64).
- Account 380 – Services, Customer Component. Direct assignment to Minot AFB Distribution (Rate 65).
- Account 381 – Meters, Customer Component. Direct assignment to Minot AFB Distribution (Rate 65).
- Account 383 – Service Regulators, Customer Component. Direct assignment to Minot AFB Distribution (Rate 65).
- Account 385 – Industrial Measuring & Regulating Station Equipment. Direct assignment to Small Interruptible and Large Interruptible (Rates 71 and 82) and Minot AFB Delivery (Rate 64).
- Account 387.1 – Cathodic Protection Equipment. Direct assignment to Minot AFB Distribution (Rate 65).

III. MONTANA-DAKOTA'S COST OF SERVICE STUDY

A. Process Steps and Structure of the Cost of Service Study

Q. Please describe the process of performing Montana-Dakota's COSS analysis.

A. Three broad steps were followed to perform the Company's COSS: (1) functionalization, (2) classification, and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include production (i.e., gas supply expenses), distribution and general. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity or revenue allocation factors.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing a COSS?

A. Yes. The factors which can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting Montana-Dakota's COSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the State of North Dakota as it pertains to cost of service studies and gas ratemaking issues.

Q. Please explain why the physical configuration of the system is an important consideration.

A. The particulars of the physical configuration of the transmission and distribution system are important. The specific characteristics of the system configuration, such as, whether the distribution system is a centralized or a dispersed one, should be identified. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple-pressure based or a single pressure-based operation.

Q. What are the specific physical characteristics of Montana-Dakota's system?

A. The physical configuration of Montana-Dakota's system is a dispersed / multiple city-gate, primarily distribution-only and multi pressure-based system. The pipeline providing the gas supply to the Wahpeton area is classified as a transmission pipeline.

Q. What was the source of the cost data analyzed in the Company's COSS?

A. All cost of service data has been extracted from the Company's total cost of service (i.e., total revenue requirement) and subsidiary schedules contained in this filing.

Q. How does the availability of data influence a COSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region and the types of load data available. Montana-Dakota maintains detailed plant accounting records for many of its distribution-related facilities.

Q. How are Montana-Dakota's classes structured for purposes of the COSS?

A. The COSS evaluated seven customer classes: Residential, Small Firm General, Large Firm General, Air Force Delivery (Rate 64), Small Interruptible Sales and Transportation, Large Interruptible Sales and Transportation, and the Minot Air Force Base Distribution (Rate 65).

Q. Please explain the customer class labeled as Minot AFB Distribution?

A. The Minot AFB Distribution customer class represents the cost of service associated with the Minot AFB distribution system Montana-Dakota purchased in 2008. The costs associated with Montana-Dakota's ownership of this system are recovered under a contract with the Minot AFB and set forth on the Air Force Distribution System Rate Schedule 65 authorized by the North Dakota Public Service Commission in Case No. PU-06-470. Montana-Dakota has included an updated cost of service analysis in this case to demonstrate that other customers are not subsidizing distribution service to Minot AFB.

Q. How do state regulatory policies bear upon a utility's COSS?

A. State regulatory policies and requirements prescribe whether there is a particular approach historically used to establish utility rates in the state. Specifically, state regulations may set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the cost allocation method utilized by the utility.

B. Classification and Allocation of Distribution Mains

Q. How did the Company's COSS classify and allocate investment in Distribution Mains?

A. The Company classified 30% of its investment in distribution mains as customer related and 70% of the investment as demand related. The customer related portion of the distribution mains investment was then allocated based on the number of customers on Montana-Dakota’s system. The demand related investment was allocated to the customer classes based on their respective contribution to peak day demand under system design weather conditions, in other words, on a “design day” basis.

Q. Please explain the basis for the Company’s choice of classification and allocation methods?

A. It is widely accepted that distribution mains (FERC Account No. 376) are installed to meet both system peak period load requirements and to connect customers to the LDC's gas system. Therefore, to ensure that the rate classes that cause the Company to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by an LDC in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the LDC's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the LDC.

Q. Is the method used by the Company to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the LDC's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of the customer's peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. For purposes of determining the customer component of distribution mains to be used in Montana-Dakota's COSS, both the zero-intercept method and the minimum system method were employed to test the reasonableness, by comparison, of the two approaches.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, American Gas

Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. With respect to Montana-Dakota's specific operating experience, is there demonstrable evidence to support the use of a customer component of distribution mains?

A. Yes. In developing an appropriate cost allocation basis for distribution mains, the two methods of cost analysis mentioned in the previous response were conducted for the Company's investment in distribution mains, by size and material type of main installed. The zero-intercept method typically uses linear regression analysis to compare unit costs of the various sized distribution mains installed on Montana-Dakota's gas system against the size (diameter) of the various distribution mains installed. This method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of its peak or annual consumption. The linear regression analysis can be expressed formulaically as follows:

$$y = mx^2 + b$$

Where: y = average cost per installed foot of Montana-Dakota's distribution mains

m = cost per installed foot, per inch of pipe diameter

x^2 = diameter squared of distribution mains

b = minimum cost per installed foot (the zero-intercept)

This equation determines that regardless of the main's diameter, the average cost of a distribution main on Montana-Dakota's gas system will be at least equal to a minimum cost per installed foot. This per foot cost component is exclusively related to the simple fact that Montana-Dakota incurs this cost to install a main, regardless of its size. That is, the installation is unrelated to either peak gas flows or average gas flows. Rather, these distinct costs are related more strongly to the process of extending the distribution mains to connect customers, which is a function of the length of distribution mains and not of the size or diameter of the mains. This is the per foot customer cost component of Montana-Dakota's distribution mains as distinguished from the per foot demand cost component, which is equal to a cost per foot times the diameter of the distribution main.

Q. Do the results of the zero-intercept method described above therefore support the 30% classification of distribution mains as customer related, used by the Company?

A. Yes. Applying the weighted average of the regression results for plastic and steel mains of $5.01 per foot cost of the "zero inch" distribution main to the Company's total footage of distribution mains results in an investment amount equivalent to approximately 25.9% of the total investment in distribution mains, on a current cost (year 2019) basis.

Q. How do the results under the zero-intercept method compare to the results under the most commonly installed, minimum-sized mains investment approach for Montana-Dakota's North Dakota service territory?

A. For the purpose of comparison, the most commonly installed, minimum-sized distribution mains analysis focused on 2-inch plastic pipe. In the last twenty-five years,1994 through 2019, 3.7 million feet out of approximately 6.7 million total feet or 55% of distribution mains installed in Montana-Dakota's North Dakota service territory was 2-inch plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic. Since 1994, the second most footage of installed distribution mains was 4-inch plastic pipe, approximately 1.36 million feet. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 35.4%. When compared to the zero-intercept analysis results, the mid-point of the 10-percentage point band-width or 30% was selected for the customer component of distribution mains.

Q. Montana-Dakota's distribution mains plant data for North Dakota indicates the installation of smaller sized pipe (1 ¼-inch or less) over the 25-year period. Why wasn't a smaller pipe size chosen for the minimum system analysis?

A. Information provided by Montana-Dakota's engineering and construction personnel indicated that use of the smaller sized pipe (i.e., less than 2-inch) for distribution mains is limited to special situations, such as a street crossing from a larger size main to provide service to two or three premises. These smaller size main segments are installed when a subdivision's underground utility infrastructure – water, sewer, power – road beds, and curbing are installed. These smaller diameter pipes are treated for plant accounting purposes as distribution mains since no service lines will be installed until a house structure is under construction and final grading of the property is complete.

Q. Would one expect there to be a strong correlation between the number of customers served by Montana-Dakota and the length of its system of distribution mains?

A. Yes. Development of the Company's distribution grid over time is a dynamic process. 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.

Recognizing that the goal is to more reasonably classify and allocate the total cost of Montana-Dakota's distribution mains facilities, it is appropriate to analyze the cost causation factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such 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 distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

C. Distribution and General Plant Classification and Allocation

Q. How were the remaining Distribution Plant costs treated in the COSS?

A. As discussed earlier, where possible, costs were directly assigned to the customer classes based on data in the Company's plant records. Weighting factors were developed for plant costs in FERC Account Nos. 380 (Services) and 381 (Meters) based on the size and type of the facilities and equipment. The classification and allocation of the remaining account balances of the directly assigned costs discussed earlier were based on the meters and distribution mains allocators, respectively. The costs in Accounts Nos. 374 (Land & Right of Way); 378 & 379 (Measurement & Regulator Station Equipment – General & City Gate); 387 (Cathodic Protection Equipment); and 375 (Structures & Improvements) were classified and allocated based on the distribution mains allocator.

Q. How were the General and Common Plant costs classified and allocated in the COSS?

A. With one exception, General and Common Plant costs were classified and allocated to the customer classes based on an internal allocation factor generated from the results of the classification and allocation of distribution plant costs. Common Intangible – Customer Care & Billing (CC&B) plant was classified as customer-related and allocated on the average number of customers.

D. Operation & Maintenance, Customer Accounts & Services, and Administrative & General Expenses

Q. How were O&M expenses classified and allocated in the COSS?

A. Generally, the classification and allocation of the Operation & Maintenance (O&M) expenses followed the treatment of the related plant accounts with the exception of Account No. 879 (Customer Installations Expense), the treatment of which followed the weighted meters allocator.

Q. Please describe the classification and allocation of Customer Accounts and Customer Service expenses in the COSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class. Exceptions to this treatment were Account Nos. 902 (Meter Reading), 903 (Customer Records & Collections) and 904 (Uncollectible Accounts). Meter reading expenses were allocated based on the total annualized number of customers weighted by meter size. A composite allocation factor was created for customer records and collections expenses, based on a study of the various functions and related activities of the responsibility areas that charged to this account. Uncollectible accounts expenses were assigned to the residential and small firm general classes based on number of customers, which reflected the historical uncollectible expense experience.

Q. Please explain the treatment of Administrative and General expenses in the COSS?

A. The majority of the A&G expenses were classified and allocated based on the internally generated allocation factor of total O&M expenses, excluding gas supply related costs and A&G. Taxes Other than Income Taxes and their corresponding [allocation basis] includes: Ad Valorem taxes [Distribution plant]; Payroll, Franchise and Other taxes [O&M excluding gas costs]; and Revenue taxes [Pro forma operating revenue].

E. Cost of Service Study Results

Q. Please explain the COSS information contained in Statement K.

A. Statement K, Schedule K-1, pages 1 – 4, provides a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the Pro Forma rate of return of 7.304 percent were to be earned for the demand, energy and customer cost components of each rate schedule along with a summary of the results by the major rate classifications, Residential, Small Firm General, Large Firm General, Air Force Delivery (Rate 64), Small Interruptible Sales and Transportation, Large Interruptible Sales and Transportation, and Air Force Distribution (Rate 65) .

Statement K, Schedule K-2, pages 1 – 18, is a report of the projected 2021 rate base and income statement as allocated to each rate schedule. The description of each allocator and the allocation factors for each class and cost component are provided in Statement K, Schedule K-3.

The COSS is based on a projected 2021 average test period for North Dakota natural gas operations sponsored by Company witness Ms. Vesey.

Q. Please summarize the results of the COSS.

A. As shown in Statement K, Schedule K-1, the overall rate of return for North Dakota natural gas service is 3.631%, based on the projected results of operations for the 12 months ended December 31, 2021, adjusted for known and measurable changes. The returns by customer class are shown below:

• Residential Service	1.853%
• Small Firm General Service	4.237%
• Large Firm General Service	5.935%
• Minot AFB Delivery	0.677%
• Small Interruptible Sales & Transportation	6.870%
• Large Interruptible Sales & Transportation	19.217%
• Minot AFB Distribution	19.339%

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you rely upon as the basis for rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

- Efficiency;
- Cost of Service;
- Value of Service;
- Stability;
- Non-Discrimination;
- Administrative Simplicity; and
- Balanced Budget.

These rate design principles draw heavily upon the “Attributes of a Sound Rate Structure” developed by James Bonbright in Principles of Public Utility

Rates. Each of these principles plays an important role in analyzing the rate design proposals of Montana-Dakota.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the concept of SAC, discussed earlier, into practice and is particularly relevant for Montana-Dakota because of the competitive supply alternatives that cap rates under its flex rates.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different. In this case, this principle is an important requirement that supports Montana-Dakota's proposed use of a single monthly Basic Service Charge for all customers within certain of its tariff schedules.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

Q. Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between proper price signals based on marginal cost and the balanced budget principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of the customer accessing the entire gas delivery system. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the utility's total revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the utility's revenue requirements while sending marginal cost price signals related to gas consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges, and the potential for revenue credits.

In the case of a local distribution company ("LDC") such as Montana-Dakota, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permits proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

A. Yes. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of retail gas rates?

A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

- System cost characteristics such as established in the COSS required by the Commission, or embedded customer, demand, and commodity related costs by type of service;
- Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
- Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and
- Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact from modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the billing determinants expected to occur during the test period used to develop the rates.

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process has to be, in part, influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Montana-Dakota's proposed revenue increase of $8,972,424 to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for Montana-Dakota's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Montana-Dakota's interclass revenue proposal?

A. Yes. Using Montana-Dakota's proposed revenue increase, and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Montana-Dakota personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that I evaluated under Montana-Dakota's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00 (Unity), as shown in Exhibit No.___(RJA-1), Proposed Revenue Allocation, under *Revenues at Equalized Rates of Return*. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective. Revenue changes under this option and all remaining options for Minot AFB Distribution will not be proposed as its revenues are determined by contract with Montana-Dakota. All revenue changes shown for Minot AFB Distribution in Exhibit No.___ RJA-1 are for illustrative purposes only.

A second option I considered was assigning the increase in revenues to Montana-Dakota's customer classes based on an equal percentage basis of its current non-gas revenues (see *Scenario A, Equal Percentage Increase*, in Exhibit No.___ RJA-1). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Montana-Dakota's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). In fact, the disparity in cost responsibility between the classes was widened. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Montana-Dakota's class revenue proposal.

A third option was to exempt the customer classes that are above parity under current rates from receiving any revenue increase. This option would preserve the current parity ratio for the Large Interruptible Sales & Transportation class (see *Scenario B*, *No Class Increase Above Parity*, in Exhibit No.___ RJA-1).

Q. What was the result of this process?

A. After further discussions with Montana-Dakota, I concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Montana-Dakota's customer classes: Residential Service (Rate Schedules 60), Small General Service (Rate Schedule 70), Large Firm General Service (Rate Schedule 70), Minot AFB Delivery Service (Rate Schedule 64), Small Interruptible Sales & Transportation Service class (Rate Schedules 71 and 81) and Large Interruptible Sales & Transportation Service (Rate Schedule 82 and 85), as shown in Exhibit No.___ RJA-1 as *Proposed Class Revenues*. In the case of the Residential Service class, the revenue adjustment ensures their proposed rates will move class revenues closer to the COSS for the class. The proposed revenue increase to the residential class will improve the class' revenue to cost ratio from 0.74 to 0.97. The Small Firm General Service (0.85), Large General Service (0.93), Minot AFB Delivery Service (0.79), and Small Interruptible Sales & Transportation Service (0.98) classes' revenue-to-cost ratios were below unity (1.00) at the Company's proposed ROR of 7.304%. The proposed revenue increases to these respective classes will result in a revenue-to-cost ratio for each of these classes at parity. The COSS results for the remaining customer classes indicate their respective class rates of return are above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue decreases in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00, as shown in Exhibit No.___ RJA-1 under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential

Service class has led me to conclude, in consultation with the Company, to refrain from revenue reductions for the remaining customer classes, or alternatively, exempting these classes from revenue increases (*Scenario B*). Instead, the proposed respective revenue adjustments of 25% of the system average increase to eligible (non-contracted) customers, will mean these classes will be slightly higher than their current parity ratio levels relative to unity. The revenue increase for Small Interruptible Sales & Transportation Service was further adjusted to reflect the minimum adjustment of 25% of the system average increase because raising the class to parity was lower than this minimum threshold.

In summary, this preferred revenue allocation approach resulted in reasonable movement of the Residential class revenue-to-cost ratio toward unity or 1.00, while providing moderation of the revenue impact on this class by requiring some level of revenue increase responsibility from all customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of class movement, and modest reduction in the existing class rate subsidies, is desirable.

Statement L, page 1, Revenues Under Current and Proposed Rates, presents summaries by customer rate schedule of the proposed revenue increase. This Statement displays the revenues calculated under the present and proposed rates for each customer tariff rate schedule. The proposed revenue increase by rate schedule and corresponding percentage is also shown.

The allocation of the total revenue increase of $8,972,424 to the respective rate schedules is presented in Statement L, page 3. The target revenue increase as a percentage of total class revenues, including gas costs, range from 12.51% to Residential, 6.55% to Small Firm General, 1.86% to Large Firm General, 2.26% to Minot AFB Delivery 2.51% to Small Interruptible, and 0.96% to Large Interruptible.

VI. MONTANA-DAKOTA'S RATE DESIGN PROPOSALS

Q. Please summarize Montana-Dakota's proposed rate design changes.

A. I will present the specific rate design changes and supporting rationale for Montana-Dakota's proposals. Montana-Dakota has proposed to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service for customers served under the following Rate Schedules: Residential Service (Rate Schedules 60 & 90), Small General Service (Rate Schedules 70, 72 74 & 92); Large General Service (Rate Schedule 70, 72, 74, & 92); Small Interruptible Sales & Transportation Service (Rate Schedules 71 and 81), and Large Interruptible Sales & Transportation Service (Rate Schedules 85 and 82), as shown on Statement L . Following the revenue increases recovered through the Basic Service Charges, except for the Residential Service and Small Interruptible Service rate schedules, the remaining allocated revenue increases for these customer classes will be recovered in their respective volumetric Distribution Delivery Charge components. The Residential Rate Schedules do not contain a Distribution Delivery Charge and the Small Interruptible Service Rate Schedules will receive a decrease in their Distribution Delivery Charges, as further described below.

Q. Please describe the proposed changes to the Basic Service Charges for the respective tariff schedules.

A. As seen on page 4 of Statement L the Basic Service Charge under Residential Rate 60 is proposed at $0.8919 per day which reflects an average monthly charge of $27.11, an increase of approximately $6.26 per month from the currently effective charge.

The Basic Service Charge applicable to Firm General Service customers with meters rated less than 500 cubic feet per hour is proposed at $0.75 per day, and $2.13 per day for customers requiring the larger meters capable of measuring gas flows of 500 cubic feet per hour or greater. The resulting average monthly charges will be $22.81 and $64.79 respectively representing an increase of $1.52 per month in the Basic Service Charge applicable to customers using meters rated less than 500 cubic feet per hour and an increase of $2.44 per month in the Basic Service Charge for customers requiring meters rated at 500 cubic feet per hour or higher. The rate calculations for the Firm General classes are included on pages 7-8 of Statement L.

The proposed Basic Service Charge applicable to Small Interruptible Sales (Rate Schedule 71) and Transportation (Rate Schedule 81) Service customers is $450.00 per month. While this level of basic charge is greater than the total allocated customer related costs for the Small Interruptible Service class, it improves the level of fixed costs attributable to the class recovered through a fixed monthly charge. In addition, this level of Basic Service Charge will permit the current large differential between the Interruptible Sales and Transportation Distribution Delivery Charges to be eliminated, resulting in a uniform volumetric rate and a decrease in the charge for both Sales Rate Schedule 71 and Transportation Rate Schedule 81customers. The rate calculations for the Small Interruptible Service class are included on page 9 of Statement L.

The proposed Basic Service Charge applicable to Large Interruptible Sales (Rate Schedule 85) and Transportation (Rate Schedule 82) Service customers is $1,600.00 per month, a $100.00 increase in the level of the current charge. As stated earlier, these proposed increases to the Basic Service Charges will provide significant improvement in the recovery of the fixed costs via fixed charges.

Q. Do increases in Basic Service Charges, such as those proposed by Montana-Dakota, discourage conservation of the natural gas commodity?

A. No. For example, under the Company's proposed increase to its Residential Basic Service Charge, customers will continue to have a financial incentive to pursue energy efficiency measures. The portion of the customer's gas bill represented by the Company's Basic Service Charge is less than half of the combined total bill, including the gas commodity charge incurred by the customer. As depicted in the accompanying Exhibit No.___(RJA-2), Rate 60 Residential Bill Comparison, the portion of the typical residential customer's annual bill represented by the average monthly Basic Service Charge increase of $6.26 per month is approximately 11% of the total bill. The effect of raising the proposed Basic Service Charge by $0.2059 per day, the equivalent of $6.38 per month in January, the month in which the most gas is typically consumed by residential heating customers, is only 7% of the total January bill. This is a relatively small amount. The commodity cost of gas[1] is 68% of the customer's bill in January, which continues to provide a strong economic price signal that may influence the customer's ongoing gas consumption decisions. In my opinion, the relatively small amount of fixed costs added to the Basic Service Charge that

[1] Montana-Dakota's proforma cost of gas in the COSS is $3.984 per Dk.

would otherwise be recovered in the volumetric Distribution Delivery Charge will not materially affect a customer's decision to use more or less gas.

By recovering its fixed distribution costs in the Residential Basic Service Charge, the Company will be able to continue promoting energy efficiency and conservation for its customers while moderately reducing the real threat of margin losses due to declining gas sales per customer.

Q. Does a volumetrically weighted rate design provide the most appropriate prices signals to customers related to gas consumption?

A. No. A volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the gas utility's ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the gas utility's system; and (4) needlessly inflate bills in the winter months, when customers face the greatest pressure on their household budgets from utility bills. Montana-Dakota's rate design proposal to increase the level of its Basic Service Charges moves in the right direction to minimize these undesirable effects and best aligns the price signals to customers with the underlying costs of providing gas delivery service.

A Basic Service Charge that better reflects the level of customer related costs will result in a customer's annual bill more accurately reflecting the non-gas revenue amounts approved by the Commission in this rate case, while customers will recognize the results of their energy conservation efforts in the amount they pay for the gas commodity in their monthly bills.

In summary, a Basic Service Charge provides increased bill stability for customers and increased revenue stability for the Company.

Q. In view of the Residential Basic Service Charge proposed by the Company, can you offer any further analysis that would evaluate the magnitude of increases to which <u>individual</u> customers will be exposed?

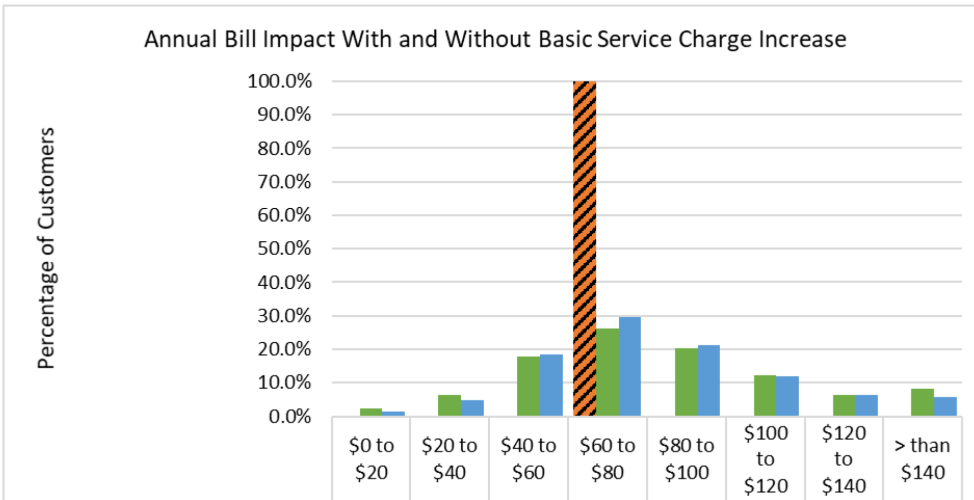
A. Yes. This can generally be assessed by analyzing how a change in rates impacts a customer's total bill, rather than the individual rate components, and is best analyzed by looking at the sum total of the customer's bills over a twelve-month period. The analysis should look at the amount of change in dollars paid instead of merely focusing on percentage increases. This is because the percentage increase in a smaller bill appears relatively high.

Q. Have you performed the analysis you recommend for the Company's Residential Basic Service Charge proposal?

A. Yes. Following as *Figure 1*, is a chart showing the impact that an increase from the current Residential Basic Service Charge to the Company's proposed $0.8919 per day Basic Service Charge, would have on bills paid by Residential customers and Residential low-income customers over a twelve-month period. This chart shows that Residential and Residential low-income customers would all see an annual increase of $60.00 to $80.00, an average monthly increase between $5.00 and $6.67 (see the bar labeled "With BSC Increase").

Figure 1 also demonstrates the comparison of the annual bill frequencies of low-income customers with those of the general population of residential customers. Although the Company does not keep records of income characteristics of its customers, it is possible to identify customers who receive bill assistance. Low-income customers generally receive LIHEAP. The Company has provided information on the annual consumption levels of LIHEAP customers. The information presented in *Figure 1* shows that the 2,683 LIHEAP customer group had annual usage profiles very similar to those of the larger Residential class. This information addresses a not uncommon perception of low-income customers, which is that they tend to be low-use customers as well.

<u>Figure 1</u>



	$0 to $20	$20 to $40	$40 to $60	$60 to $80	$80 to $100	$100 to $120	$120 to $140	> than $140
With BSC Increase	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Residential, No BSC Increase	2.5%	6.3%	17.8%	26.2%	20.4%	12.2%	6.5%	8.2%
Low-Income, No BSC Increase	1.5%	4.9%	18.6%	29.6%	21.3%	12.0%	6.3%	5.9%

Q. Have you evaluated the impact on low-income customers' bills if the Company's proposed revenue increase allocated to Residential customers were collected entirely in a new volumetric Distribution Delivery Service Charge?

A. Yes. *Figure 1* also provides a side-by-side comparison of the impact to Residential low-income customers from collecting the proposed Residential revenue increase in a new Distribution Delivery charge versus the proposed increase in the Basic Service Charge. The chart shows how the dispersion of the annual bill increases change when the revenue from the proposed Basic Service

Charge increase is moved to a new volumetric Distribution Delivery Charge. Under the “No BSC Increase” scenario, 45.5% or 1,219 of the low-income annual bill increases will be larger than $80.00, including 5.9% of annual bill increases exceeding $140.00, representing 157 low-income customers. This compares with 25.0% or 670 low-income annual bill increases below $60.00, including only 1.5% or 39 low-income customers that would experience an annual bill increase of $0 - $20.00.

Q. Are there other proposed rate design changes to Montana-Dakota’s non-residential rate schedules?

A. Yes. Apart from the equalization of the Small Interruptible Sales and Transportation Distribution Delivery Charges described earlier, Montana-Dakota proposes to add a Distribution Delivery Charge for the Firm General Service customers requiring meters rated at 500 cubic feet per hour or higher (Large Firm General) separate from the current Distribution Delivery Charge, which will only apply to Firm General Service customers requiring meters rated less than 500 cubic feet per hour (Small firm General). This will allow for better alignment of the Firm General Service Rate Schedule components with the corresponding class cost of service results and proposed revenue apportionment as well as guard against cross-subsidization between Small and Large Firm General Service customers. The Firm General Service Distribution Delivery Charges will continue to exclude Firm Contract Demand Service (Rate Schedule 74) customers. However, Montana-Dakota proposes to increase the Distribution Demand Charges for both Small and Large Rate Schedule 74 customers. The proposed rate components for all Firm General Service Rate Schedules are shown in Statement L, pages 7-8.

VII. WAHPETON RATE SCHEDULES

Q. Please describe the rate changes under the two-phase integration of Customers in the Wahpeton service area of Great Plains Natural Gas Co. into Montana-Dakota's North Dakota service territory.

A. As discussed by Company witness, Ms. Bosch, the integration of Wahpeton customers into Montana-Dakota's rate schedules will include changes in Rate Schedules and the rate structures within them. In Phase 1 of the integration, Wahpeton Residential Service (new Montana-Dakota Rate Schedule 63) and Firm General Service (new Montana-Dakota Rate Schedule 73) customers will be converted from a monthly Basic Service Charge of $3.50 to a proposed daily Basic Service Charge of $0.25, an average monthly increase of $4.10. The Distribution Delivery Service multi-block rate structure for Rate Schedules 63 and 73 will be converted to a single block rate of $1.028 per Dk.

Similar to the two new rate schedules for residential and firm general service for Wahpeton, new Montana-Dakota Wahpeton rate schedules will be established for small and large interruptible sales gas service (currently provided under Wahpeton Interruptible Service – General (Rate Schedule 71) and Transportation Service (currently provided under Interruptible Transportation Service Rate 80). Both the sales and transportation tariffs will reflect a small and large rate classification. Customers' rates will be converted from a monthly Basic Service Charge of $3.50 to a proposed monthly Basic Service Charge of $180.00. The Distribution Delivery Service multi-block rate structure for Rate Schedules 76, 86, 83 and 84 will be converted to a single block rate of $0.670 per Dk.

The proposed rate components for all Rate Schedules applicable to Wahpeton customers are located in Statement L, pages 11 to 14.

Q. Please describe the proposed rate changes under Phase 2 of integration of the Wahpeton customers into Montana-Dakota's North Dakota service territory.

A. In Phase 2 of the integration, the proposed daily Basic Service Charges applicable to Wahpeton Residential Service (new Montana-Dakota Rate Schedule 63) and Firm General Service (new Montana-Dakota Rate Schedule 73) customers will increase to $0.333 for Rate Schedule 63, $0.50 for Rate Schedule 73 customers using meters rated less than 500 cubic feet per hour (Small Firm General), and $1.00 for Rate Schedule 73 customers requiring meters rated at 500 cubic feet per hour or higher (Large Firm General). The uniform Distribution Delivery Service Charge of $1.028 per Dk under Phase 1 will change to $0.649 per Dk for Rate Schedule 63, $0.632 per Dk for Rate Schedule 73 – Small Firm General, and $0.507 per Dk Rate Schedule 73 – Large Firm General.

The Phase 2 monthly Basic Service Charge for customers served under Small Interruptible Sales Service (Rate Schedule 76) will increase from $180.00 to $250.00 and for customers served under Large Interruptible Sales Service (Rate Schedule 86), the Basic Service Charge will increase to $500.00. The uniform Distribution Delivery Service Charge of $0.670 per Dk under Phase 1 will change to $0.608 per Dk for Rate Schedule 76 and $0.656 per Dk for Rate Schedule 86 in Phase 2. Exhibit No.____(RJA-3) provides a summary of the Phase 1 and 2 rate structure and corresponding unit rates for the Wahpeton customers.

VIII. CUSTOMER BILL IMPACTS

Q. Has Montana-Dakota prepared bill comparisons for its Residential Service customers?

A. Yes. The monthly and annual bill impacts for a typical Residential customer using 88 dekatherms (Dk) per year is shown on page 1 of Exhibit No.___(RJA-2), Rate 60 Residential Bill Comparison for Residential gas service. The average monthly increase for this residential customer under the Company's proposed rate design is $6.26 or 12.50%.

Q. What are the corresponding bill comparisons for Montana-Dakota's Small Firm General and Large Firm General customers?

A. The monthly and annual bill impacts for a typical Small Firm General customer using 191 Dk per year is shown on page 1 of Exhibit No.___(RJA-4), Rate 70 Bill Comparison for Firm General gas service. The average monthly increase for this Small Firm General customer under the Company's proposed rate design is $6.38 or 6.50%. The monthly and annual bill impacts for a typical Large Firm General customer using 1,229 Dk per year is shown on page 2 of the exhibit. The average monthly increase for this Large Firm General customer under the Company's proposed rate design is $10.22 or 1.84%.

A presentation of the annual billing impacts for the Residential and Firm General Service classes is provided in Pages 16-29 of Statement L.

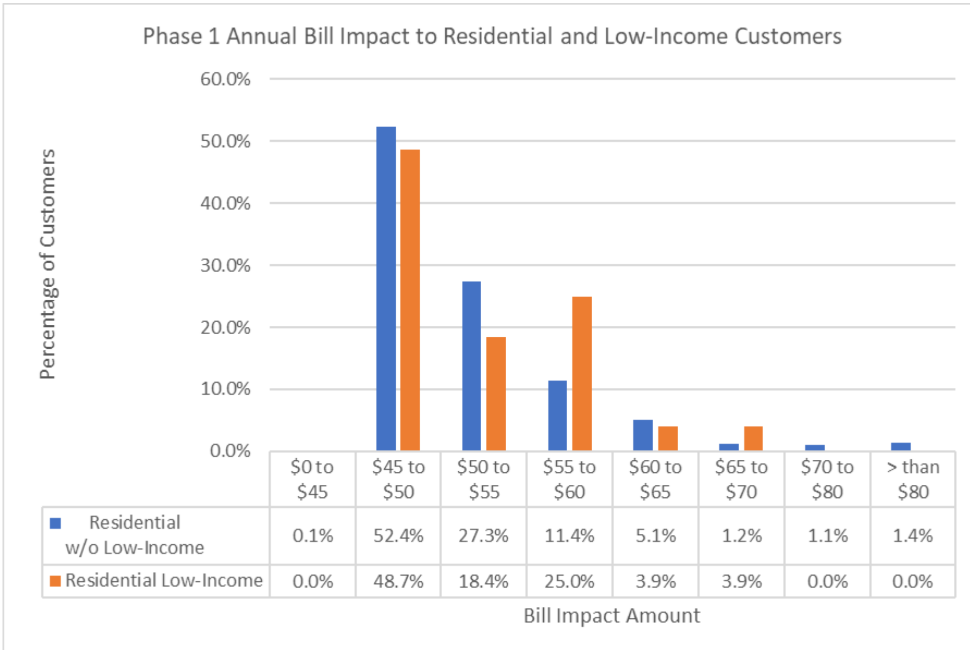
Q. Has Montana-Dakota prepared bill comparisons for its Wahpeton Residential Service customers?

A. Yes. The monthly and annual bill impacts for a typical Wahpeton Residential customer using 80 dekatherms (Dk) per year is shown on page 1 of Exhibit No.___(RJA-5), Wahpeton Rate 63 Residential Bill Comparisons. The average monthly increase for this residential customer under the Company's proposed Phase 1 rate design is $4.10 or 10.45%. Page 2 of Exhibit No.____(RJA-5) shows the largely revenue neutral impact on a typical Wahpeton Residential customer of the proposed Phase 2 rates.

Q. Have you evaluated the impact on Wahpeton low-income customers' bills for the Company's proposed revenue increase allocated to Residential customers in Phase 1 and 2 of the transition to Montana-Dakota tariff schedules?

A. Yes. *Figure 2* below provides a side-by-side comparison of the impact to Wahpeton Residential and low-income customers from collecting the proposed Residential revenue increase in Phase 1 of the proposed transition of Wahpeton customers into the Montana-Dakota rate structure. The chart shows the dispersion of the annual bill increases when the revenue increase is recovered under the new proposed daily Basic Service Charge and the current Distribution Delivery Service multi-block rate structure is converted to a single block rate. Approximately half of both Wahpeton Residential (52.4%) and low income Residential (48.7%) customers will experience an annual bill increase between $45.00 and $50.00 in Phase 1 of the transition. Another 38.7% of Wahpeton Residential customers and 43.4% of Wahpeton low-income Residential customers will see and annual increase under $60.00.

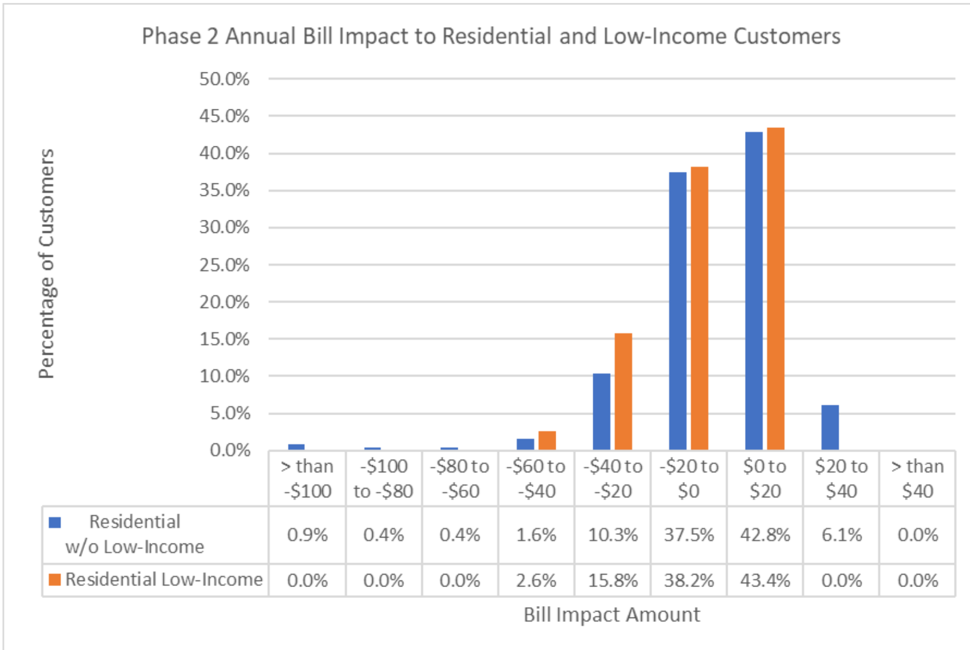
<u>Figure 2</u>



Q. What will be the impact on Wahpeton Residential and low-income Residential customers under Phase 2 of the transition?

A. *Figure 3* below provides a side-by-side comparison of the impact to Wahpeton Residential and low-income Residential customers from collecting the proposed Residential revenue increase in Phase 2 of the proposed transition of Wahpeton customers into the Montana-Dakota rate structure. The chart shows the revenue neutral nature of the Phase 2 rates. 80.3% of Wahpeton Residential customers and 81.6% of low-income Residential customers will experience annual bill impacts between $20.00 decreases to $20.00 increases. Another 10.3% of Wahpeton Residential customers and 15.8% low-come Residential customers will experience annual bill decreases between $20.00 and $40.00.

Figure 3



Q. Does this conclude your direct testimony?

A. Yes.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA

Case No. PU-20-____
Exhibit ___ (RJA-1)

Proposed Revenue Allocation

	Total North Dakota	Total Residential	Total Small Firm General	Total Large Firm General	Total Air Force Delivery	Total Small Interruptible	Total Large Interruptible	Total MAFB Distribution
Revenue to Cost Ratio Under Current Rates	0.82	0.74	0.85	0.93	0.79	0.98	1.68	2.09
Revenues at Equalized Rates of Return								
Revenue Increase	8,972,424	8,400,619	823,541	643,396	29,291	34,181	(720,541)	(238,063)
Total revenue at equalized rates of return	50,857,794	32,725,297	5,340,964	9,590,977	139,664	1,776,988	1,065,967	217,937
Parity Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Secnario A: Equal Percentage Increase								
Revenue Increase	8,972,424	5,210,682	967,694	1,916,695	23,643	373,333	382,695	97,681
Total revenue at equalized rates of return	50,857,794	29,535,360	5,485,117	10,864,276	134,016	2,116,140	2,169,203	553,681
Percent Increase	21.42%	21.42%	21.42%	21.42%	21.42%	21.42%	21.42%	21.42%
Parity Ratio	1.00	0.90	1.03	1.13	0.96	1.19	2.03	2.54
Secnario B: No Class Increase Above Parity								
Revenue Increase	8,972,424	7,476,196	823,541	643396	29291	0	0	0
Total revenue with no increase to classes above Parity	50,857,794	31,800,874	5,340,964	9,590,977	139,664	1,742,807	1,786,508	456,000
Percent Increase	21.42%	30.74%	18.23%	7.19%	26.54%	0.00%	0.00%	0.00%
Parity Ratio	1.00	0.97	1.00	1.00	1.00	0.98	1.68	2.09
Secnario C: Minimum Class Increase of 25% of System Average								
minimum 25% of system average increase (to elegible customers 1/)						5.57%	5.57%	
Revenue Increase	8,972,424	7,344,027	823,541	643,396	29,291	97,070	35,099	0
Total revenue at 25% system average minimum	50,857,794	31,668,705	5,340,964	9,590,977	139,664	1,839,877	1,821,607	456,000
Percent Increase	21.42%	30.19%	18.23%	7.19%	26.54%	5.57%	1.96%	0.00%
Parity Ratio	1.00	0.97	1.00	1.00	1.00	1.04	1.71	2.09

1/ "eligible customers" excludes contract rate customers

Source: Statement L

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE
Projected 2021

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$81.03	$87.41	$6.38	7.87%
February	15	78.97	84.73	5.76	7.29%
March	12	69.07	75.46	6.39	9.25%
April	9	56.44	62.61	6.17	10.93%
May	5	41.19	47.57	6.38	15.49%
June	2	28.55	34.73	6.18	21.65%
July	1	25.25	31.63	6.38	25.27%
August	1	25.25	31.63	6.38	25.27%
September	2	28.55	34.73	6.18	21.65%
October	4	37.20	43.58	6.38	17.15%
November	9	56.44	62.61	6.17	10.93%
December	13	73.06	79.44	6.38	8.73%
Total	88	$601.00	$676.13	$75.13	12.50%

Average Increase per Month	$6.26
Annual Basic Service Charge increase percent	11%
January Basic Service Charge increase percent	7%

RATE 60	Current	Proposed	
Basic Delivery Charge	$0.6860	$0.8919	
Distribution Delivery	$0.000	$0.000	
Cost of Gas	3.984	$3.984	68%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
WAHPETON TRANSITION PHASE 1 & 2 RATE DESIGN

PROJECTED 2021

GPNG Tariff	MDU Wahpeton Specific Tariff	Equivalent MDU Tariff	Current Rate	Proposed Phase 1 Rate	Proposed Phase 2 Rate	MDU Rate
Rate 65 - Firm Service						
Residential, Rate 65	MDU Rate 63	Rate 60				
Basic Servcie Charge			$3.50 or $0.1151 per day	$0.2500	$0.3330	$0.8919
Distribution Delivery Charge				$1.028	$0.649	$0.000
First 10 Dk			$1.072			
Over 10 Dk			$0.822			
Firm General - Small, Rate 65	MDU Rate 73, Small<500 CFH	Rate 70, Small				
Basic Servcie Charge			$3.50 or $0.1151 per day	$0.250	$0.500	$0.750
Distribution Delivery Charge				$1.028	$0.632	$1.116
First 10 Dk			$1.072			
Over 10 Dk			$0.822			
Firm General - Large Rate 65	MDU Rate 73, Large>500 CFH	Rate 70, Large				
Basic Servcie Charge			$3.50 or $0.1151 per day	$0.250	$1.000	$2.130
Distribution Delivery Charge				$1.028	$0.507	$0.887
First 10 Dk			$1.072			
Over 10 Dk			$0.822			
Rate 71 - Interruptible Sales Service						
Annual Dk < 100,000	MDU Rate 76	Rate 71 (Sales)				
Basic Servcie Charge			$3.50	$180.00	$250.00	$450.00
Distribution Delivery Charge				$0.6700	$0.6080	$0.5560
First 400 Dk			$1.0160			
Next 2,600 Dk			$0.7675			
Over 3,000 Dk			$0.6140			
Annual Dk > 100,000	MDU Rate 86	Rate 85 (Sales)				
Basic Servcie Charge			$3.50	$180.00	$500.00	$1,600.00
Distribution Delivery Charge				$0.6700	$0.6560	$0.2390
First 400 Dk			$1.0160			
Next 2,600 Dk			$0.7675			
Over 3,000 Dk			$0.6140			
Rate 80 - Interruptible Transportation Service						
Annual Dk < 100,000	MDU Rate 83	Rate 81 (Transport)				
Basic Servcie Charge			$3.50	$180.00	$250.00	$450.00
Distribution Delivery Charge				$0.6700	$0.6080	$0.5560
First 400 Dk			$1.0160			
Next 2,600 Dk			$0.7675			
Over 3,000 Dk			$0.6140			
Annual Dk > 100,000	MDU Rate 84	Rate 82 (Transport)				
Basic Servcie Charge			$3.50	$180.00	$500.00	$1,600.00
Distribution Delivery Charge				$0.6700	$0.6560	$0.2390
First 400 Dk			$1.0160			
Next 2,600 Dk			$0.7675			
Over 3,000 Dk			$0.6140			

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

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	36	$195.29	$207.82	$12.53	6.42%
February	35	188.37	200.45	12.08	6.41%
March	25	142.25	151.43	9.18	6.45%
April	18	107.80	114.79	6.99	6.48%
May	10	69.92	74.52	4.60	6.58%
June	4	40.29	43.01	2.72	6.75%
July	2	31.34	33.50	2.16	6.89%
August	2	31.34	33.50	2.16	6.89%
September	3	35.47	37.88	2.41	6.79%
October	8	60.28	64.27	3.99	6.62%
November	19	112.62	119.91	7.29	6.47%
December	29	161.54	171.93	10.39	6.43%
Total	191	$1,176.51	$1,253.01	$76.50	6.50%

Average Increase per Month $6.38

RATE 70	Current	Proposed
Basic Delivery Charge	$0.70	$0.750
Distribution Delivery	$0.811	$1.116
Cost of Gas	4.011	$4.011

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

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	210	$1,076.17	$1,094.61	$18.44	1.71%
February	205	1,045.91	1,063.73	17.82	1.70%
March	153	801.32	815.42	14.10	1.76%
April	115	616.03	627.17	11.14	1.81%
May	71	405.91	413.79	7.88	1.94%
June	37	239.91	245.13	5.22	2.18%
July	28	198.57	203.17	4.60	2.32%
August	26	188.92	193.38	4.46	2.36%
September	33	220.63	225.53	4.90	2.22%
October	57	338.40	345.22	6.82	2.02%
November	121	644.96	656.56	11.60	1.80%
December	173	897.76	913.38	15.62	1.74%
Total	1229	$6,674.49	$6,797.09	$122.60	1.84%

Average Increase per Month $10.22

RATE 70	Current	Proposed
Basic Delivery Charge	$2.05	$2.13
Distribution Delivery	$0.811	$0.887
Cost of Gas	4.011	$4.011

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
WAHPETON RATE 63 BILL COMPARISON - PHASE I
RESIDENTIAL GAS SERVICE
Projected 2021

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$83.44	$88.28	$4.84	5.80%
February	16	88.60	92.90	4.30	4.85%
March	12	67.95	72.18	4.23	6.23%
April	8	46.81	50.45	3.64	7.78%
May	4	25.15	29.22	4.07	16.18%
June	1	8.91	12.87	3.96	44.44%
July	1	8.91	13.12	4.21	47.25%
August	1	8.91	13.12	4.21	47.25%
September	1	8.91	12.87	3.96	44.44%
October	2	14.32	18.49	4.17	29.12%
November	8	46.81	50.45	3.64	7.78%
December	11	62.79	66.81	4.02	6.40%
Total	80	$471.51	$520.76	$49.25	10.45%

Average Increase per Month $4.10

RATE 63	Current	Proposed Phase 1
Basic Service Charge	$3.50	$0.250
Distribution Charge - all Dk		$1.028
Distribution Charge First 10 Dk	$1.0720	
Distribution Charge Over 10 Dk	$0.8220	
Cost of Gas	$4.3408	$4.3408

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
WAHPETON RATE 63 BILL COMPARISON - PHASE II
RESIDENTIAL GAS SERVICE
Projected 2021

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$88.28	$85.17	($3.11)	-3.52%
February	16	92.90	89.15	(3.75)	-4.04%
March	12	72.18	70.20	(1.98)	-2.74%
April	8	50.45	49.91	(0.54)	-1.07%
May	4	29.22	30.28	1.06	3.63%
June	1	12.87	14.98	2.11	16.39%
July	1	13.12	15.31	2.19	16.69%
August	1	13.12	15.31	2.19	16.69%
September	1	12.87	14.98	2.11	16.39%
October	2	18.49	20.30	1.81	9.79%
November	8	50.45	49.91	(0.54)	-1.07%
December	11	66.81	65.21	(1.60)	-2.39%
Total	80	$520.76	$520.71	($0.05)	-0.01%

Average Increase per Month $0.00

RATE 63	Proposed Phase 1	Proposed Phase 2
Basic Service Charge	$0.25	$0.333
Distribution Charge - all Dk	$1.028	$0.649
Cost of Gas	$4.3408	$4.3408

ATRIUM ECONOMICS

Ronald J. Amen

Managing Partner, Atrium Economics LLC

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time-of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

Bachelor of Science, Business Administration, Finance and Economics, University of Nebraska– Lincoln, 1978, United States

YEARS EXPERIENCE

42

PROFESSIONAL ASSOCIATIONS

American Gas Association

Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Policy, Strategy and Analysis

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canadian National Energy Board, Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)

Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018)

Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC.

McDowell Rackner & Gibson Law Firm (2015 – 2016)

Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)

Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Resource Planning, Strategy and Financial Analysis

Fortis BC Energy, Inc. (2011)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2 003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

Cost Allocation, Pricing Issues and Rate Design

Kansas City, KS Board of Public Utilities (2019 – 2020) (pending)

Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)

Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)

Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)

Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which will incorporate the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently working with Tacoma Power for the potential incorporation of financial forecasting capabilities and revenue requirements development into the COSA model. Future project work involves working on the re-design of the general service and industrial rate schedules, economic development rate strategies, demand response rates, and other innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities;
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions;
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA);
- Collected and reviewed data for cost-based fees including:
  - Application Fees
  - Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs; and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discuss accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017)

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in four general rate cases before the Indiana Utility Regulatory Commission.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)

In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In a pending general rate case, Mr. Amen is sponsoring expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement.

Utility System Operations and Organizational Development

Philadelphia Gas Works (2017, 2020)

Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-20-___

Direct Testimony
of
Stephanie Bosch

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

A. Yes. My name is Stephanie Bosch, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota).

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

A. I am responsible for the proper application of the Company's gas and electric rates in the Customer Care and Billing System (CC&B), the application of tariffs, and the preparation of miscellaneous rate filings.

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

A. I graduated from the University of North Dakota in 1995 with a Bachelor of Business and Public Administration degree in Banking and Financial Economics. I joined Montana-Dakota in June 1997 as a Rate Clerk in the Regulatory Affairs Department and realized positions of increasing responsibility within the Regulatory Affairs Department until 2011 when I left the Company. In 2013 I returned to the Company as a Regulatory Analyst before attaining my current position in August of 2015.

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

A. The purpose of my testimony is to present the gas revenue at current rates, included in Statement F, Schedule F-1 of this Application, the proposed rate schedules provided in Appendix B to the Application, the integration of Wahpeton, North Dakota customers into Montana-Dakota's North Dakota gas tariff, and other proposed changes in the Company's tariff.

I am also presenting the apportionment of the interim increase to the various rate classes and the proposed interim rate schedules provided in Appendix A to this Application for Interim Increase in Natural Gas Rates.

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

A. Yes. I have previously presented testimony before this Commission and the Public Service Commissions of Montana and Wyoming and the Public Utilities Commission of Minnesota.

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

A. I am sponsoring the proposed rate schedules provided in Appendix B to the Application, with the exception of the proposed Cost of Gas – Wahpeton Rate 89, which is sponsored by Ms. Vesey, and Exhibit No.___(SB-1) through Exhibit No.___(SB-3).

I am also sponsoring the proposed interim rate schedules provided in Appendix A to the Interim Application.

Q. Please explain the calculation of the revenue at current rates included in Statements F, Schedule F-1?

A. The Company applied the Basic Service Charges and Distribution Charges applicable under each rate schedule, and as authorized in Case No. PU-17-295 for Montana-Dakota and Case Nos. PU-17-075 and PU-17-490 for Great Plains, to the number of customers and level of usage identified by Mr. Shoemake to derive the revenues shown on Statement F, Schedule F-1, pages 1 and 2. Interruptible sales and transportation customers were priced at the applicable rate schedule's maximum rate per Dk, unless service is provided under a contract rate. The Cost of Gas rates and the Cost of Propane rate are reflective of the 2021 gas commodity charges and demand costs as of July 2020, excluding the surcharge.

Wahpeton Rate Schedules

Q. Company witnesses have described the integration of the Great Plains' Wahpeton service area into Montana-Dakota's North Dakota service territory. Could you please expand on this discussion from a tariff and rate implementation standpoint?

A. Yes, as previously noted by Ms. Kivisto and Ms. Vesey, Montana-Dakota is proposing to incorporate Wahpeton, North Dakota, currently provided service under the Great Plains North Dakota gas tariff, into

Montana-Dakota’s North Dakota gas tariff. While the Company is proposing the integration be effective upon Commission approval of the Company’s request, the implementation of this integration will need to be accomplished in phases.

Q. Why is the Company proposing that the implementation of this integration be accomplished in phases?

A. Today, customers in Wahpeton receive natural gas service under the rates and general provisions authorized by this Commission under the Great Plains North Dakota gas tariff. As such, Wahpeton customers are billed independent of Montana-Dakota's customers and under a Great Plains' bill.

In order to accomplish the move to a Montana-Dakota bill, a Wahpeton customer's service must be stopped under its Great Plains' rate schedule, evaluated to determine the customer's correct rate classification under Montana-Dakota's service requirements, and a new service started under the proper Montana-Dakota rate schedule. While the evaluation of a customer's service may be straightforward for some customers, others may require a further evaluation such as an on-site review to determine the correct Montana-Dakota rate classification.

Additionally, the Company's proposed phase-in integration of Wahpeton customers is affected by the Company’s proposed interim request. Upon Commission approval of the Company’s request to implement interim rates, Wahpeton customers will begin being billed the authorized interim rate, under the Great Plains North Dakota gas tariff, which will continue through the implementation of final rates in this case. If the final revenue requirement is ultimately less than the interim request implemented, an interim refund will be necessary. As the interim rate will be billed under a Great Plains' rate schedule and on a Great Plains' bill, the Company believes it is appropriate, that in the event of a refund, the refund also be accomplished on Great Plains' billing system and presented on a Great Plains' bill. This provides consistency and transparency from the start of the interim through any refund that may be necessary.

Q. Please describe the Company's phase-in approach.

A. The Company is proposing a two-phase approach for incorporating Wahpeton into Montana-Dakota's North Dakota gas tariff. Phase I will commence with the implementation of final rates in this case and the start of the transition process of integrating Wahpeton into Montana-Dakota's North Dakota gas tariff. Separate rate schedules applicable only to the community of Wahpeton and surrounding areas will be established under Montana-Dakota's North Dakota gas tariff for residential, firm general, small and large interruptible sales and small and large interruptible transportation service, consistent with Montana-Dakota's North Dakota gas rate schedules.

While new Montana-Dakota rate schedules will be established in Phase I, reflecting the rates described by Mr. Amen, the actual billing of

Wahpeton customers will need to remain within Great Plains' billing system with customers continuing to receive a Great Plains' bill. As Phase I reflects the start of the transition to Montana-Dakota's gas tariff, Wahpeton customers will retain their current firm or interruptible service classification throughout this initial phase. For example, a Wahpeton Firm Gas Service Rate 65 customer today will remain a firm gas service customer throughout Phase I, but service will now be provided for under either Montana-Dakota Rate 63 or 73 where the charges included on these two new rate schedules will reflect the same Basic Service Charges and Distribution Charges for Phase I as the rate differentiation between these two rate schedules will not occur until Phase II when the actual movement of customers occurs.

The same will be true of Wahpeton's Interruptible Sales Service Rate 71 customers today. Wahpeton's interruptible sales customers will remain interruptible sales customers throughout Phase I, but service will now be provided for under either Montana-Dakota's Rate 76 or 86 where the charges included on these two new rate schedules will reflect the same Basic Service Charges and Distribution Charges in Phase I as the rate differentiation between these two rate schedules will not occur until Phase II when the actual movement of customers will occur.

The same will hold true for Interruptible Transportation Service Rate 80 today; however, currently the only Wahpeton transportation customer is served under a contract rate whose rate is not affected by this case.

The availability and rate provisions applicable under all Wahpeton rate schedules, as included in Montana-Dakota's proposed North Dakota gas tariff included in Appendix B, will reflect both phases in order to readily identify the transition path from the current Great Plains tariff's availability provisions to a customer's Phase II rate classification as shown in the proposed Wahpeton rate schedules included herein as Exhibit No.__(SB-1).

A bill message will be included on all Wahpeton customers' bills, throughout this phase, informing Wahpeton customers that the rates and service provided are now being provided for under Montana-Dakota's gas tariff and to contact the Company with any questions regarding this integration. This bill message will be in addition to the required customer notices included in all customers' bills at the time final rates are implemented in this rate proceeding.

The Company will also be considering different means of communicating with customers, such as direct mailings or community meeting(s) when appropriate given the current pandemic.

Q. In addition to the new rate schedules, are there rate structure changes proposed in Phase I that will further the alignment of Wahpeton rates with Montana-Dakota's North Dakota gas rates?

A. Yes. Montana-Dakota is proposing three rate structure changes that provide a Phase I alignment with Montana-Dakota's rate schedules: (1) the daily application of the Basic Service Charge under the Wahpeton residential and firm general rate schedules, (2) the splitting of the Basic Service Charges applicable under Firm General Service - Wahpeton Rate 73 into two separate charges, dependent on whether the meters are rated under or over 500 cubic feet per hour. However, the actual rate differential under Rate 73 will not occur until Phase II when a customer review can be conducted and the customer's service stopped and started under the proper Montana-Dakota service classification. (3) The replacement of the current blocked distribution rate structure, applicable under all Wahpeton rate schedules today, with a flat distribution charge, consistent with all of Montana-Dakota's gas rate schedules.

Montana-Dakota implemented both the daily application of the Basic Service Charges applicable under the Company's firm service rate schedules as well as the replacement of a blocked distribution rate structure with a flat distribution charge in Case No. PU-399-02-183. The above noted proposed changes are reflected in the rates described by Mr. Amen.

Q. Please describe Phase II of the Wahpeton integration.

A. The Company is proposing the second phase of the integration start twelve months after Phase I rates are implemented. Phase II involves the actual movement of Wahpeton customers to a Montana-Dakota rate schedule based on Montana-Dakota's service requirements and the phase in which Wahpeton customers will start receiving a Montana-Dakota bill.

Under this phase, the firm service class will be split into two rate classes as defined in Montana-Dakota's General Provisions Rate 100's Rules for Application of Gas Service (Section V.3.a and b).

- Residential Gas Service Rate 63 will be available to customers using firm natural gas for domestic purposes.
- Firm General Gas Service Rate 73 will be available to all non-residential firm gas service customers. The Basic Service Charge rate differential will also be applicable under Phase II.

Similarly, the interruptible sales and transportation service classes will also be split into two rate classes as the availability provisions of the Wahpeton interruptible rate schedules has been revised for consistency with Montana-Dakota's interruptible rate schedules.

Interruptible Sales Service:

- Small Interruptible Sales Gas Service Rate 76 will available to interruptible sales service customers with annual requirements not to exceed 100,000 Dk.
- Large Interruptible Sales Gas Service Rate 86 will be available to interruptible sales service customers with annual requirements that exceed 100,000 Dk.

Transportation Service:

- Small Interruptible Transportation Gas Service Rate 83 will be available to interruptible transportation service customers with annual requirements not to exceed 100,000 Dk.

- Large Interruptible Transportation Gas Service Rate 84 will be available to interruptible transportation service customers with annual requirements that exceed 100,000 Dk.

A summary of the proposed Wahpeton rate schedules is included herein as Exhibit No. __(SB-2) along with the number of customers affected by the rate re-classifications.

The actual transition of Wahpeton customers from a Great Plains customer to a Montana-Dakota customer, in accordance with the above outlined Montana-Dakota service requirements, will occur across a billing month. Following each bill cycle in the month of the transition, customers in Wahpeton will have their Great Plains services stopped and new services started under the proper Montana-Dakota rate schedules. The Company will coordinate the timing of the stopping and starting of each service with a customer’s actual meter read cycle in order to avoid a customer receiving two partial month bills, one from Great Plains and the other from Montana-Dakota. After the transition, the customer’s next monthly bill will be a Montana-Dakota bill.

Phase II will also have a change in rates as described by Mr. Amen. While Phase II rates, in total, will be revenue neutral, individual customers will be impacted differently depending on the customer's rate re-classification and consumption. Bill inserts will again be included with all Wahpeton customers’ bills notifying them of the change in rates and of their new Montana-Dakota bill.

Q. What other tariff changes will Wahpeton customers see as a result of the integration?

A. In Great Plains' last rate case (Case No. PU-17-075), the Company proposed a number of changes to its North Dakota gas tariff. Many of those tariff changes aligned Great Plains' North Dakota gas rate tariff with Montana-Dakota's North Dakota gas rate tariff; however, there were some differences that did remain between the two companies. With the integration of Wahpeton customers into Montana-Dakota, the Company needs to address those remaining differences here.

- Firm and interruptible service extensions will now be reviewed under Montana-Dakota's Interruptible Gas Service Extension Policy Rate 119 and Firm Gas Service Extension Policy Rate 120.
- Montana-Dakota does not have minimum service connection charges as currently provided for in Great Plains' North Dakota General Terms and Conditions Rate 100 for the installation and turn on of the gas meter and regulator. These separate charges will stop with service connections on and after Phase I.
- Currently Wahpeton customers are assessed a late payment charge (LPC) of 1 1/3 percent per month on any amount not paid by the due date shown on the bill. Montana-Dakota's LPC rate is one percent per month and will be the rate assessed on past due Wahpeton bills on and after Phase I.

- Currently Great Plains' tariff provides for a $30.00 reconnection fee for seasonal or temporary customers for customers requesting the reconnection of service where the same customer discontinued the same service during the preceding 12-month period. Seasonal reconnection fees will now be assessed Wahpeton customers in accordance with Montana-Dakota's Rate 100 Section V.20.

Proposed Tariff Changes

Q. Would you briefly describe any additional changes the Company is proposing to its Montana-Dakota gas tariffs?

A. The Company is proposing the following changes to the gas tariffs as clearly identified in the legislative copy of the tariffs provided in Appendix B of the Application:

- The Company is proposing an entirely new volume of its gas rate book, designated herein as NDPSC Volume 8, to supersede the current volume 7, in order to reflect the removal of "A Division of MDU Resources Group, Inc." in the tariff header of all rate schedules as well as to incorporate the new Wahpeton rate schedules into Montana-Dakota's rate book.
- The rates described by Mr. Amen have been incorporated into the proposed tariffs.
- Clarify that the charges included in the determination of a penalty payment as provided for under Penalty for Failure to Curtail or Interrupt provision applicable under the Company's Interruptible

Service Rates 71 and 85 and Transportation Rates 81 and 82 tariffs. The proposed change clarifies that all charges billed under the Company's Firm General Gas Service Rate 70, excluding the Basic Service Charge, are billed on any gas taken in the event of a penalty situation.

- Update the Temperature Sensitive Use per Customer identified on the Distribution Delivery Stabilization Mechanism Rate 87 tariff to reflect the daily base use per customer per day resulting from the corresponding rates' regression analyses performed for the normalization of firm general volumes in this case.
- Update the annual authorized usage by rate used in the determination of the Non-Residential Reconnection Fee for Seasonal or Temporary Customers, under General Provisions Rate 100, to reflect each respective rate class' average annual use from this case.
- Introduce a monthly Manual Meter Reading Charge assessed customers who request to have their gas meter read manually each month in lieu of the Company installing an AMR-equipped meter to obtain meter reads.
- There are other minor wording changes listed throughout the Company's rate book to improve the readability of the rate without modifying any conditions, update the rate and/or page references

or are self-explanatory. These changes are clearly denoted on the tariff sheets in the legislative format.

Q. Is the Company proposing any changes to the Company's Extension Policies Rates 119 and 120?

A. Yes. The Company is proposing to update the Levelized Annual Revenue Requirement (LARR) identified on the tariff to reflect the costs and return included in this case.

The Company is also proposing to revise the Maximum Allowable Investment (MAI) formula, used to determine a firm extension's cost participation, to recognize the rates charged under Firm General Contracted Demand Service Rate 74 include a Distribution Demand Charge, not a Distribution Delivery Charge.

Q. Did the Company incorporate the changes in this rate increase application that were proposed to Firm General Contracted Demand Service Rate 74 and to the Reconnection Fee for Seasonal Customers provision under General Provisions Rate 100 that are pending before this Commission in Case No. PU-20-335?

A. No, the Company did not. In Case No. PU-20-335, Montana-Dakota proposed changes to clarify certain provisions related to contract requirements under Rate 74 and to revise paragraph 20 under Section 5 of Rate 100 to include the Capacity Reservation Charge applicable under the Gwinner Pipeline Capacity Reservation Charge Rate 75 tariff in the determination of the seasonal reconnection charge.

Montana-Dakota will incorporate any changes to these two rate schedules that are ultimately authorized by this Commission in Case No. PU-20-335 in subsequent tariff submissions in this case.

Q. How was the proposed interim revenue requirement apportioned among the customer classes?

A. The interim revenue increase of $6,893,176, identified by Ms. Vesey, is proposed to be billed as a separate line item on the bill based on 17.116 percent of the amounts billed under the Basic Service Charge and the Distribution Delivery or Demand Charges applicable under the Company's rate schedules, excluding flexible contract rate customers.

The calculations supporting the application of the interim increase to each rate class are provided in Statement K attached to the Application for Interim Increase in Natural Gas Rates. The proposed tariff sheets reflect the proposed interim increase of 17.116 percent to be applied to the amount billed under the Basic Service Charge and the Distribution Delivery or Demand Charges. The interim rate will not be applicable to the amount billed under the Cost of Gas or Propane. The interim increase represents an average increase of 6.0 percent over total projected 2021 revenues, including the cost of gas revenues. Page 2 of Exhibit No. ___(SB-3) shows a typical residential bill for a Montana-Dakota customer reflecting the proposed interim increase, showing an average monthly increase of $3.57 from current rates. Page 3 of Exhibit No. ___(SB-3) shows a typical residential bill for a Wahpeton customer reflecting the proposed interim increase, showing an average monthly increase of $1.77 from current rates.

Q. Does this conclude your testimony?

A. Yes.

Exhibit No.___(SB-1)
Proposed Montana-Dakota Wahpeton Rate Schedules

RESIDENTIAL GAS SERVICE – WAHPETON Rate 63

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule to Montana-Dakota Utilities Co.'s Residential Gas Service – Wahpeton Rate 63. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule and is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Firm Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton for all domestic uses. See Rate 100, §V.3, for definition on class of service.

Rate:

Phase I:

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$1.028 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Phase II:

Basic Service Charge:	$0.333 per day
Distribution Delivery Charge:	$0.649 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

RESIDENTIAL GAS SERVICE – WAHPETON Rate 63

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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

The foregoing schedule is subject to Rates 100 through 124 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 - WAHPETON Rate 73

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule to Montana-Dakota Utilities Co.'s Firm General Gas Service – Wahpeton Rate 73. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Firm Gas Service - Rate 65 rate schedule and is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Firm Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

Phase I:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$1.028 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$1.028 per dk

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

Phase II:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.632 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$1.000 per day
Distribution Delivery Charge:	$0.507 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

The foregoing schedule is subject to Rates 100 through 124 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 – WAHPETON Rate 76

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule to Montana-Dakota Utilities Co.'s Small Interruptible General Gas Service – Wahpeton Rate 76. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule and is available to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Interruptible Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton 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 100,000 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 73. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Phase I:

Basic Service Charge:	$180.00 per month
Distribution Delivery Charge:	
Maximum	$0.670 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

SMALL INTERRUPTIBLE GENERAL GAS SERVICE – WAHPETON Rate 76

Phase II:

Basic Service Charge:	$250.00 per month
Distribution Delivery Charge:	
Maximum	$0.608 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the Cost of Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

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 Wahpeton firm 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.11.

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 charges applicable under Firm General Gas Service Rate 73, (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state

TRANSPORTATION SERVICE – WAHPETON Rates 83 and 84

Availability:

For the community of Wahpeton this service is applicable 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:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Interruptible Transportation Service - Rate 80 rate schedule to Montana-Dakota Utilities Co.'s Transportation Service – Wahpeton Rates 83 and 84. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Interruptible Transportation Service - Rate 80 rate schedule and is available to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Interruptible Transportation Service".

Phase II Availability *(effective start date of Phase II)*:
Small Interruptible General Gas Transportation Service - Wahpeton Rate 83:
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 100,000 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 - Wahpeton Rate 76. 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 – Wahpeton Rate 73.

Large Interruptible General Gas Transportation Service - Wahpeton Rate 84:
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually metered at a single delivery point, 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 - Wahpeton Rate 86. 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 – Wahpeton Rate 73.

Rate:

Under Rate 83 or 84, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 76 or Rate 86, the Basic Service Charge applicable under Rate 83 or Rate 84 shall be waived.

Phase I:

Basic Service Charge:		
Rate 83	$180.00 per month	
Rate 84	$180.00 per month	
	Rate 83	Rate 84
Maximum Rate per dk	$0.670	$0.670
Minimum Rate per dk	$0.130	$0.130

Phase II:

Basic Service Charge:		
Rate 83	$250.00 per month	
Rate 84	$500.00 per month	
	Rate 83	Rate 84
Maximum Rate per dk	$0.608	$0.656
Minimum Rate per dk	$0.130	$0.130

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. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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 73. 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.11.

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 customer's behalf, shall be billed at the charges applicable under Firm General Gas Service - Wahpeton Rate 73, (excluding Basic Service Charge), 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.

6. CUSTOMER USE OF NON-DELIVERED VOLUMES - 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 9.b. Gas volumes supplied by Company will be charged at charges applicable under Firm General Gas Service - Wahpeton Rate 73. The Company is under no obligation to notify customer of non-delivered volumes.

7. REPLACEMENT OR SUPPLEMENTAL SALES SERVICE - 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.

8. 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 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.

   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.21.

9. DAILY IMBALANCE:
   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.

   b. In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.

   c. 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. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

    a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Averages Prices" published by Gas Daily for Emerson, Manitoba during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

11. METERING REQUIREMENTS:

a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards an additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made

c. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

12. DAILY NOMINATION REQUIREMENTS:

a. Customer or customer's shipper or agent shall advise the Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC timelines, of the dk requirements customer has requested to be delivered at each delivery point 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.

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

TRANSPORTATION SERVICE – WAHPETON Rates 83 and 84

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.13, or any amendments 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. The foregoing schedule is subject to Rates 100 through 124 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 - WAHPETON Rate 86

Availability:

Phase I Availability *(effective dates for Phase I)*:
Phase I reflects a transition period of moving customers from the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule to Montana-Dakota Utilities Co.'s Large Interruptible General Gas Service – Wahpeton Rate 86. Service available under this rate schedule is the same as service available under the former Great Plains Natural Gas Co.'s Interruptible Gas Service - Rate 71 rate schedule and is available to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk. Customers receiving service under this rate schedule will receive a Great Plains Natural Gas Co. bill whereby the service is identified as "Interruptible Gas Service".

Phase II Availability *(effective start date of Phase II)*:
For the community of Wahpeton for all interruptible general gas service customers whose interruptible natural gas load will exceed 100,000 dk annually as metered at a single delivery point.

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 73. 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.

Rate:

Phase I:

Basic Service Charge:	$180.00 per month
Distribution Delivery Charge:	
Maximum	$0.670 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Phase II:

Basic Service Charge:	$500.00 per month
Distribution Delivery Charge:	
Maximum	$0.656 per dk
Minimum	$0.130 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.13, or any amendments or alterations thereto.

Cost of Gas:
The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas - Wahpeton 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:

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 Wahpeton firm 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.11.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain 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 73, (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required 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 90 days prior to the end of the initial term. Absent execution of 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. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or 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 (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company, prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such

enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 124 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.
Gas Utility - North Dakota
Summary of Proposed Changes for Wahpeton
Case No. PU-20-____

Change	GPNG ND Current	MDU ND Proposed	# of Customers
Rate Classifications			
Firm Service	Rate 65		
Residential		Rate 63	1,900
Firm General		Rate 73	
Small < 500 CFH			282
Large < 500 CFH			145
Total Firm Service			2,327
Interruptible Sales Service	Rate 71		
Small < 10,000 Dk Annually		Rate 76	17
Large > 10,000 Dk Annually		Rate 86	2
			19
Interruptible Transportation Service 1/	Rate 80		
Small < 10,000 Dk Annually		Rate 83	0
Large > 10,000 Dk Annually		Rate 84	0
			0
Other Tariff Changes			
Firm Gas Extensions	Rate 105	Rate 120	
Free Footage - Mains	Up to 95 feet	Not provided for	
Free Footage - Service Lines	Up to 65 feet	Not provided for	
Refunds	Without interest	With interest	
		No refunds < $25.00	
Service Line Connections		Not billed separately	
Input loads up to 400,000 Btu/hour	$25.00		
Input loads > 400,000 Btu/hour	$50.00		
Interruptible customers	$100.00		
Late Payment Charge Rate	1.33%	1.00%	
Seasonal Reconnections	$30.00	2/	

1/ Today the only Transportation Service Rate 80 customer is a contract rate customer.

2/ Residential - the Basic Service Charge applicable during the period service was not being used and a charge of $30.00. The minimum will be based on standard overtime rates for reconnecting service after normal business hours. Non-Residential - the Basic Service Charge applicable during the period service was not being used. The reconnection charge applicable to seasonal business concerns will have the distribution revenue collected, while in service for customers whose consumption exceeds the annual authorized usage for the class. from the Basic Service Charge revenue for the time the customer was not in service in addition to a $30.00 charge.

Montana-Dakota Utilities Co.
Gas Utility - North Dakota
Revenues Under Current and Proposed Rates - Interim

	Projected 2021			Total	Proposed	
Customer Class/Rate	Customers	Dk	Revenues	Proposed Revenue	Revenue Increase	Percent Increase
Residential - Rate 60	96,225	8,467,441	$57,827,536	$61,951,427	$4,123,891	7.1%
Firm General Service - Rate 7	16,276	8,378,483	46,440,489	48,721,031	2,280,542	4.9%
Air Force - Rate 64						
Firm	1	36,425	159,201	161,612	2,411	
Interruptible	2	396,550	1,137,554	1,154,035	16,481	
Total Air Force	3	432,975	1,296,755	1,315,647	18,892	1.5%
Small Interruptible						
Sales - Rate 71	87	514,844	2,103,283	2,230,907	127,624	6.1%
Transportation - Rate 81	61	1,015,084	817,156	957,020	139,864	17.1%
Total Small IT	148	1,529,928	2,920,439	3,187,927	267,488	9.2%
Large Interruptible						
Sales - Rate 85	0	0	0	0	0	
Transportation - Rate 82	7	4,741,919	1,043,054	1,089,068	46,014	4.4%
Total Large IT	7	4,741,919	1,043,054	1,089,068	46,014	4.4%
Firm Gas - GPNG Rate 65	2,327	293,200	1,644,594	1,708,243	63,649	3.9%
Interruptible - GPNG						
Sales - GPNG Rate 71	19	792,211	3,193,676	3,286,334	92,658	2.9%
Transportation - Rate 80	9	1,125,190	382,113	382,113		
Total IT	28	1,917,401	3,575,789	3,668,447	92,658	2.6%
Montana-Dakota	112,659	23,550,746	109,528,273	116,265,100	6,736,827	
GPNG - ND	2,355	2,210,601	5,220,383	5,376,690	156,307	
Total North Dakota	115,014	25,761,347	$114,748,656	$121,641,790	$6,893,134	6.0%

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

Month	Dk	Present Rate 1/	Proposed Rate	Amount of Increase	% Increase
January	15	$81.03	$84.67	$3.64	4.49%
February	15	78.97	82.26	3.29	4.17%
March	12	69.07	72.71	3.64	5.27%
April	9	56.44	59.96	3.52	6.24%
May	5	41.19	44.83	3.64	8.84%
June	2	28.55	32.07	3.52	12.33%
July	1	25.25	28.89	3.64	14.42%
August	1	25.25	28.89	3.64	14.42%
September	2	28.55	32.07	3.52	12.33%
October	4	37.20	40.84	3.64	9.78%
November	9	56.44	59.96	3.52	6.24%
December	13	73.06	76.70	3.64	4.98%
Total	88	$601.00	$643.85	$42.85	7.13%
Average Increase per Month				$3.57	

Rate 60	Current	Proposed
Basic Delivery Charge	$0.686	$0.686
Distribution Delivery	$0.000	$0.000
Projected Cost of Gas	$3.984	$3.984
Interim Rate		17.116%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
GPNG ND RATE 65 BILL COMPARISON - INTERIM
RESIDENTIAL GAS SERVICE

Month	Dk	Present Rate 1/	Proposed Rate	Amount of Increase	% Increase
January	15	$83.44	$86.58	$3.14	3.76%
February	16	88.60	91.88	3.28	3.70%
March	12	67.95	70.66	2.71	3.99%
April	8	46.81	48.88	2.07	4.42%
May	4	25.15	26.48	1.33	5.29%
June	1	8.91	9.69	0.78	8.75%
July	1	8.91	9.69	0.78	8.75%
August	1	8.91	9.69	0.78	8.75%
September	1	8.91	9.69	0.78	8.75%
October	2	14.32	15.29	0.97	6.77%
November	8	46.81	48.88	2.07	4.42%
December	11	62.79	65.36	2.57	4.09%
Total	80	$471.51	$492.77	$21.26	4.51%
Average Increase per Month				$1.77	

Rate 60	Current	Proposed
Basic Delivery Charge	$3.50	$3.50
Distribution Charge - First 10 Dk	$1.0720	$1.0720
Distribution Charge - Over 10 Dk	$0.8220	$0.8220
Projected Cost of Gas	$4.3408	$4.3408
Interim Rate		17.116%