MONTANA-DAKOTA
UTILITIES CO.
A Subsidiary of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501
701-222-7900
www.montana-dakota.com

July 15, 2024

Mr. Will Rosquist
Regulatory Division Administrator
Montana Public Service Commission
1701 Prospect Avenue
PO Box 202601
Helena, MT 59620-2601

RE: Application and Notice of Change in Natural Gas Utility Rates
Docket No. 2024.05.061

Dear Mr. Rosquist:

Montana-Dakota Utilities Co. (Montana-Dakota or Company) herewith submits its Application and Notice to increase its rates for natural gas service pursuant to the Montana Code Annotated, Title 69, Chapter 3, regarding regulation of utilities; Title 2, Chapter 4, regarding administrative proceedings; and this Commission's rules regarding the filing of utility rate change applications (Administrative Rules of Montana (ARM) §38.5.101, et seq.). Montana-Dakota also submits its Application for an Interim Increase in accordance with the requirements set forth in ARM §38.5.501 through §38.5.506.

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

The increase in natural gas utility rates is driven primarily by the investments made since the last rate case. This includes the continued investment in distribution facilities to improve system safety and reliability, with corresponding increases to depreciation expenses related to these assets. Furthermore, the Company’s costs of doing business are increasing despite efforts to control such operation and maintenance costs.

Authorization of the requested increase in revenues will provide Montana-Dakota a reasonable opportunity to earn a fair rate of return on its Montana natural gas operations. The Company proposes a total increase in distribution revenues of $9,400,268 as shown on Statement M, page 2 based on an average test year for the twelve months ended December 31, 2023, adjusted for known and measurable changes.

The proposed increase will affect approximately 88,900 natural gas customers in Montana. The proposed change in rates will affect customer classes by the following amounts and percentages:

Class	Amount	Percent Increase
Residential	$8,168,854	16.40%
Firm General	1,195,101	3.76%
Small Interruptible	4,821	0.28%
Large Interruptible	31,492	2.52%
Total	$9,400,268	11.11%

Montana-Dakota also requests interim rate relief as set forth in its Application for Interim Increase in Natural Gas Utility Rates in the amount of $7,984,385 to take effect October 1, 2024. The interim rate increase was calculated in accordance with ARM §38.5.506.

Pursuant to ARM §38.5.503, the attached Notice has been served (as a part of this filing) to this Commission and the Montana Consumer Counsel and also mailed or emailed to all parties on the Certificate of Service, which includes interested parties that participated in the last general rate case (Docket No. 2020.06.076).

In support of the Company's request, the following documents are included with this Letter of Transmittal:

- Notice and Certificate of Service
- The Application including:
    - Appendix A – Current Rate Schedules
    - Appendix B - Proposed Final Rate Schedules including a redlined version of tariffs denoting proposed changes
- The Application for Interim Increase in Natural Gas Utility Rates including:
    - Proposed Interim Rate Schedules
    - Statements and Workpapers underlying the interim request
- Prefiled Direct Testimony and Exhibits in support of the Application
- Supporting Statements and Workpapers required by the Commission's filing requirements, ARM §38.5.103 through §38.5.180. The requirement to submit a marginal cost study under ARM §38.5.176 was waived by the Commission in Docket No. 2024.05.061 (Notice of Commission Action issued on June 25, 2024).

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 inquiries, correspondence, and pleadings to:

Mr. Michael W. Green
Crowley Fleck PLLP
900 N. Last Chance Gulch, Suite 200
Helena, MT 59601
mgreen@crowleyfleck.com

The original and ten (10) copies of this Letter of Transmittal, Application and Notice, Appendices, Testimony and Exhibits, Statements, and Application for Interim Increase in Natural Gas Utility Rates, are hereby filed with the Montana Public Service Commission.

Four (4) copies of same have this day been mailed to the Montana Consumer Counsel, P.O. Box 201703, Helena, Montana 59620-1703. All of the materials included in this Application are available upon request.

Sincerely,

Travis Jacobson

Travis R. Jacobson
Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Establish Increased Rates for Natural Gas Service	))))	Docket No. 2024.05.061

NOTICE

An Application to increase natural gas utility rates was filed with the Montana Public Service Commission on July 15, 2024 by Montana-Dakota Utilities Co. Such Application proposes a revenue increase of $9,400,268 representing an overall percentage increase of 11.1 percent.

Montana-Dakota has also requested that an interim increase of $7,984,385 to be effective October 1, 2024.

Pursuant to Administrative Rules of Montana §38.5.503, all parties listed on the Certificate of Service have been mailed and/or emailed this Notice. Parties desiring a complete copy of the said Application will be promptly provided a copy upon receipt of a written request directed to:

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

Dated this 15th day of July 2024.

Travis Jacobson

Travis R. Jacobson
Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

CERTIFICATE OF SERVICE

I certify that on the 15th day of July 2024, a true and accurate copy of Montana-Dakota Utilities Co.'s Application and Notice of Change in Natural Gas Utility Rates in Docket No. 2024.05.061 has been e-filed with the Montana Public Service Commission and served by mail and/or email to the following:

Will Rosquist
Montana Public Service Commission
1701 Prospect Avenue
PO Box 202601
Helena, MT 59620-2601
wrosquist@mt.gov

Jason Brown
Montana Consumer Counsel
111 N. Last Chance Gulch, Suite 1B
P.O. Box 201703
Helena, MT 59601-1703
jbrown4@mt.gov

Mike Green
Crowley Fleck
900 N. Last Chance Gulch
Suite 200
Helena, MT 59601
mgreen@crowleyfleck.com

Electronic Service Only:
ssnow@mt.gov
ahicks@crowleyfleck.com

/s/ Terese M. Birnbaum
Terese M. Birnbaum
terese.birnbaum@mdu.com
Regulatory Analyst
Montana-Dakota Utilities Co.

Michael Green
Wiley Barker
Crowley Fleck PLLP
900 N. Last Chance Gulch, Suite 200
Helena, MT 59601
Phone: (406) 449-4165
Fax: (406) 449-5149
mgreen@crowleyfleck.com
wbarker@crowleyfleck.com

Attorneys for Montana-Dakota

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MONTANA

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Establish Increased Rates for Natural Gas Service	))))	Docket No. 2024.05.061

* * * * *

APPLICATION AND NOTICE

Montana-Dakota Utilities Co., (hereinafter referred to as Montana-Dakota, Applicant, or Company) submits this application to the Montana Public Service Commission for authority to establish increased rates for natural gas service in Montana. The Applicant in the above-entitled proceeding respectfully submits the following Application and Notice, tariffs, and information in support thereof.

In support of its Application, Montana-Dakota respectfully states the following:

I.

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

II.

The Company's Certificate of Incorporation and Amendments thereto have previously been filed with the Montana Public Service Commission (PSC or Commission). Such Certificate and Amendments are hereby incorporated by reference.

III.

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

Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

IV.

That the following described rate schedules 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
Original Sheet No. 1	Table of Contents	
Original Sheet No. 2	Communities Served	
37th Revised Sheet No. 3	Rate Summary Sheet	
1st Revised Sheet No. 4	Thermal Zone Boundaries	
Original Sheet Nos. 11-11.1	Residential Gas Service	60
Original Sheet Nos. 21-21.1	Firm General Gas Service	70
Original Sheet Nos. 22-22.3	Small Interruptible General Gas Service	71
Original Sheet Nos. 23-23.1	Optional Seasonal General Gas Service	72
Original Sheet Nos. 27-27.2	Firm General Contracted Demand Service	74
Original Sheet Nos. 32-32.9	Transportation Service	81/82
Original Sheet Nos. 34-34.3	Large Interruptible General Gas Service	85
Original Sheet Nos. 36-36.1	Gas Tax Tracking Adjustment	87
3rd Revised Sheet No. 36.2	Gas Tax Tracking Adjustment	87
Original Sheet Nos. 37-37.5	Gas Cost Tracking Adjustment Procedure	88
Original Sheet No. 38	Universal System Benefits Charge	89
2nd Revised Sheet No. 39	Conservation Program Tracking Mechanism	90
Original Sheet Nos. 49-49.1	Table of Contents Conditions of Service	100
Original Sheet Nos. 49.2-49.23	Conditions of Service	100
Original Sheet Nos. 50-50.1	Gas Meter Testing Program	101
Original Sheet Nos 68-68.1	Interruptible Gas Service Extension Policy	119
Original Sheet Nos. 69-69.7	Firm Gas Service Extension Policy Rate 120	120
Original Sheet No. 74	Replacement, Relocation and Repair of Gas Service Lines	124

V.

Montana-Dakota respectfully hereby files the following described proposed rate schedules for natural gas service, copies attached hereto as Appendix B, which substitute for the rate schedules as noted below. The following described proposed rate schedules are proposed to be effective on a final basis in this Docket. The Rate Summary Sheet (Sheet No. 3) will be submitted upon final disposition of the Company’s request in this Docket.

Volume No. 7	Description	Rate
1st Revised Sheet No. 1	Table of Contents	
1st Revised Sheet No. 11	Residential Gas Service	60
1st Revised Sheet No. 21	Firm General Gas Service	70
1st Revised Sheet No. 22	Small Interruptible General Gas Service	71
1st Revised Sheet No. 23	Optional Seasonal General Gas Service	72
1st Revised Sheet No. 27	Firm General Contracted Demand Service	74
1st Revised Sheet No. 32.1	Transportation Service	81/82
1st Revised Sheet No. 34	Large Interruptible General Gas Service	85
4th Revised Sheet No. 36.2	Gas Tax Tracking Adjustment	87
1st Revised Sheet Nos. 37.1 - 37.5	Gas Cost Tracking Adjustment Procedure	88
1st Revised Sheet Nos. 49 - 49.1	Conditions of Service	100
1st Revised Sheet No. 49.3	Conditions of Service	100
1st Revised Sheet Nos. 49.7 - 49.23	Conditions of Service	100
1st Revised Sheet No. 50	Gas Meter Testing Program	101
Original Sheet Nos. 64 - 64.1	Summary Billing Plan	115

VI.

That the existing rates of Montana-Dakota are unjust, unreasonable, and not compensatory. The new rates will allow Montana-Dakota an opportunity to fully recover its costs of providing natural gas service and to earn a just and reasonable rate of return on its natural gas property devoted to providing service to its Montana natural gas customers.

VII.

The new rates contained herein will provide additional revenues in the annual amount of $9,400,268, based on a twelve months ended December 31, 2023 test year, adjustment for known and measurable changes, for natural gas service rendered to customers in Montana. This request amounts to a 11.11 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, and 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 $7,984,385 as set forth in the enclosed Application for Interim Increase in Natural Gas Rates.

X.

This Application and Notice is submitted in accordance with the provisions of Title 69 of the Montana Code Annotated and the rules and regulations promulgated by the Public Service Commission of the State of Montana.

WHEREFORE, Applicant respectfully requests that the Public Service Commission of the State of Montana:

1. Grant interim rate relief to Applicant in the amount of $7,984,385 in accordance with Applicant's Application for Interim Increase in Natural Gas Rates, submitted herewith;
2. Approve and adopt the proposed rate changes as set forth in Appendix B of this Application that will produce an annual increase in revenues of $9,400,268 to be effective upon final disposition of this Docket; and
3. Grant such other and additional relief as the Commission shall deem just and proper.

Respectfully submitted this 15th day of July 2024.

MONTANA-DAKOTA UTILITIES CO.

By ______________________________

Michael W. Green
Crowley Fleck PLLP
Attorney for the Applicant
900 N. Last Chance Gulch, Suite 200
Helena, Montana 59601

Montana-Dakota Utilities Co.

Montana Natural Gas Tariffs - Current

Appendix A

Public Service Commission of Montana

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

Natural Gas Service

Volume No. 7
Original Sheet No. 1

TABLE OF CONTENTS

Issued: June 22, 2020

By: Travis R. Jacobson
Director – Regulatory Affairs

For Office Use Only – Do Not Print Below This Line

Docket No. 2020.06.076

Service rendered on and
after April 1, 2021

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

COMMUNITIES SERVED

NATURAL GAS SERVICE

Rocky Mountain Region

Belfry	Fromberg	Pryor
Billings*	Hardin	Rockvale
Bridger	Joliet	Silesia
Crow Agency	Laurel	
Edgar	Park City	

Badlands Region

Baker	Ismay	Savage
Fairview	Malta	Sidney
Forsyth	Miles City	St. Marie
Fort Peck	Nashua	Terry
Frazer	Poplar	Whitewater
Glasgow	Richey	Wibaux
Glendive	Rosebud	Wolf Point
Hinsdale	Saco	

*Designates Region Office

Issued: June 22, 2020

By: Travis R. Jacobson
Director - Regulatory Affairs

For Office Use Only – Do Not Print Below This Line

Docket No. 2020.06.076

Service rendered on and after April 1, 2021

Public Service Commission of Montana

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

Natural Gas Service

Volume No. 7
37th Revised Sheet No. 3
Canceling 36th Revised Sheet No. 3

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	CTA	Cost of Gas	Total Rate/ Dk
Residential Rate 60 1/	11	$0.30 per day	$1.352	$0.009	$3.721	$5.082
Firm General Service Rate 70 1/	21					
Meters rated < 500 cubic feet		$0.60 per day	$1.577	$0.009	$3.721	$5.307
Meters rated > 500 cubic feet		$1.75 per day	$1.491	$0.009	$3.721	$5.221
Small Interruptible Gas Rate 71 1/	22	$312.00 per month	(Maximum) $0.794		$2.484	(Maximum) $3.278
Optional Seasonal Gas Service Rate 72 1/	23					
Meters rated < 500 cubic feet		$0.60 per day	$1.577	$0.009	$1.959	$3.545
Meters rated > 500 cubic feet		$1.75 per day	$1.491	$0.009	$1.959	$3.459
Contracted Demand Service Rate 74 1/	27		(Demand Charge)			
Meters rated < 500 cubic feet		$0.60 per day			(Capacity Charge)	$11.840
Meters rated > 500 cubic feet		$1.75 per day	$4.890		(COG/Dk)	$2.721
Transportation Service	32					
Small Interruptible Rate 81 1/		$312.00 per month				
Maximum			$0.794			$0.794
Minimum			$0.101			$0.101
Large Interruptible Rate 82 1/		$567.25 per month				
Maximum			$0.582			$0.582
Minimum			$0.050			$0.050
Large Interruptible Gas Rate 85 1/	34	$567.25 per month	(Maximum) $0.582		$2.484	(Maximum) $3.066

1/ Tax Tracking Adjustment of 22.6700% applicable to Basic Service Charge and Distribution Delivery Charge.

Issued: June 7, 2024 **By:** Travis R. Jacobson
Director - Regulatory Affairs

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Docket No. 2023.09.084

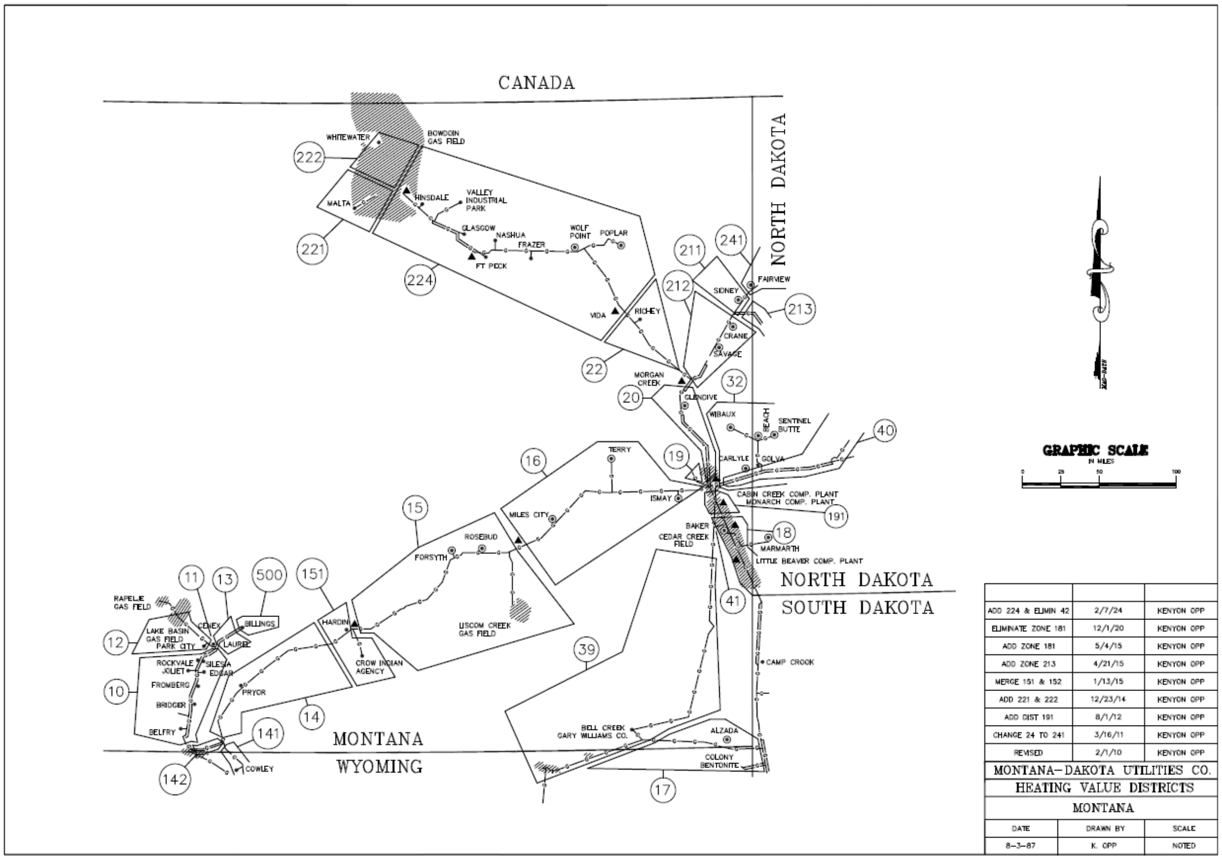
Effective with service rendered on and after July 1, 2024

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

Natural Gas Service

Volume No. 7
1st Revised Sheet No. 4
Canceling Original Sheet No. 4

THERMAL ZONE BOUNDARIES



ADD 224 & ELIMIN 42	2/7/24	KENYON OPP
ELIMINATE ZONE 181	12/1/20	KENYON OPP
ADD ZONE 181	5/4/15	KENYON OPP
ADD ZONE 213	4/21/15	KENYON OPP
MERGE 151 & 152	1/13/15	KENYON OPP
ADD 221 & 222	12/23/14	KENYON OPP
ADD DIST 191	8/1/12	KENYON OPP
CHANGE 24 TO 241	3/16/11	KENYON OPP
REVISED	2/1/10	KENYON OPP

MONTANA–DAKOTA UTILITIES CO.
HEATING VALUE DISTRICTS
MONTANA

DATE	DRAWN BY	SCALE
8–3–87	K. OPP	NOTED

Issued: February 8, 2024

By: Travis R. Jacobson
Director – Regulatory Affairs

For Office Use Only – Do Not Print Below This Line

Docket No. 2024.02.022

Service rendered on and
after May 1, 2024

RESIDENTIAL GAS SERVICE Rate 60

Availability:

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

Rate:

Basic Service Charge:	$0.30 per day
Distribution Delivery Charge:	$1.352 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.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88
3. Universal System Benefits Charge Rate 89
4. Conservation Program Tracking Mechanism Rate 90

Low-Income Discount:

Customers qualifying for and receiving energy assistance through the Low Income Energy Assistance Program (LIEAP) administered by the State of Montana

Department of Public Health and Human Services (DPHHS) shall obtain a discount from the amount billed under this rate schedule. The applicable discount, as set forth below, will be administered based upon the percentage of poverty guidelines established by DPHHS and information supplied to the Company by DPHHS at the time the customer qualifies for LIEAP assistance.

% Of Federal Poverty	Discount Rate
0-60%	30%
61%-90%	25%
91%-maximum allowed	20%

General Terms and Conditions:

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

Availability:

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

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.60 per day
Distribution Delivery Charge	$1.577 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$1.75 per day
Distribution Delivery Charge:	$1.491 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.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88

3. Universal System Benefits Charge Rate 89
4. Conservation Program Tracking Mechanism Rate 90

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-124 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

SMALL INTERRUPTIBLE GENERAL GAS SERVICE
Rate 71

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas fueled 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 treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$312.00 per month	
Distribution Delivery Charge:	Maximum $0.794 per dk	Minimum $0.101 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.

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

SMALL INTERRUPTIBLE GENERAL GAS SERVICE
Rate 71

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88
3. Universal System Benefits Charge Rate 89

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. Customers taking service hereunder agree that the Company, without prior notice, shall have the right to curtail or interrupt such service whenever, in the 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 Rate 100, §V.10.

2. STANDBY REQUIREMENTS:
   a. If Company-approved equipment and fuel for standby service is not installed and maintained, the Company, in its discretion, may install automatic shut-off equipment in order to allow for the interruption of natural gas supply. The cost of the equipment and its installation shall be paid for by customer. The cost shall be the current market price for such equipment including the current installation costs. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

SMALL INTERRUPTIBLE GENERAL GAS SERVICE
Rate 71

b. Customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of automatic shut-off equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

c. Customer's firm load must be separately metered if Company-approved equipment and fuel for standby service is not installed and maintained.

3. 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 the 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 inter-rupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

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

SMALL INTERRUPTIBLE GENERAL GAS SERVICE
Rate 71

5. OBLIGATION TO NOTIFY THE COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify the 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 customer equal to the penalty amounts the Company must pay to the interconnecting pipeline caused by customer's action.

6. 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.

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

7. RULES - The foregoing schedule is subject to Rates 100-124 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

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

Availability:

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

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.60 per day
Distribution Delivery Charge:	$1.577 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$1.75 per day
Distribution Delivery Charge:	$1.491 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.

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88
3. Universal System Benefits Charge Rate 89
4. Conservation Program Tracking Mechanism Rate 90

General Terms and Conditions:

1. 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 -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	\$0.60 per day
For customers with meters rated over 500 cubic feet per hour	\$1.75 per day
Distribution Demand Charge:	\$4.89 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.

FIRM GENERAL CONTRACTED DEMAND SERVICE
Rate 74

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88
3. Universal System Benefits Charge Rate 89

Determination of Monthly Billing Demand:

Customer's billing demand will be determined in consultation with the Company. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

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 meter installation.

FIRM GENERAL CONTRACTED DEMAND SERVICE
Rate 74

General Terms and Conditions:

1. Customers with standby gas generators required to take service under this schedule are not required to execute a contract. Other customers choosing to take service under this schedule will be required to execute a contract applicable 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.

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 the 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 of 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 the 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 requirements 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 pursuant to the Company's effective Large Interruptible General Gas Service Rate 85. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70.

Rate:

Basic Service Charge:

Rate 81	Rate 82
$312.00 per month	$567.25 per month

Transportation Charges:	Rate 81	Rate 82
Maximum Rate per dk	$0.794	$0.582
Minimum Rate per dk	$0.101	$0.050

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Universal System Benefits Charge Rate 89

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. Customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

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

3. MULTIPLE SERVICES THROUGH ONE METER:
   a. In the event customer desires firm sales service in addition to gas transportation service, customer shall request such firm volume requirements, and upon approval by the 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. 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 customer receives only gas transportation service in any billing period).

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

5. STANDBY REQUIREMENTS:
   a. If Company-approved equipment and fuel for standby service is not installed and maintained, the Company, in its discretion, may install automatic shut-off equipment in order to allow for the interruption of natural gas supply. The cost of the equipment and its installation shall be paid for by customer. The cost shall be the current market price for

such equipment including the current installation costs. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

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

c. Customer's firm load must be separately metered if Company-approved equipment and fuel for standby service is not installed and maintained.

6. 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 the 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.

7. CUSTOMER USE OF NON-DELIVERED VOLUMES - In the event customer's gas is not being delivered to the receipt point for any reason and customer continues to take gas, customer shall be subject to any applicable penalties or charges set forth in Paragraph 11.b. Gas volumes supplied by Company will be charged at charges applicable under Firm General Gas Service Rate 70 (excluding the Basic Service Charge). The Company is under no obligation to notify customer of non-delivered volumes.

8. REPLACEMENT OF 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.

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

10. RECONNECTION FEE - Transportation customers who cease service and then resume service within the succeeding 12 months, shall be subject to a reconnection charge as specified in Rate 100, §V.21.

11. DAILY IMBALANCE -
    a. To the extent practicable, customer and the Company agree to the daily balancing of volumes of gas received and delivered on a thermal basis. Such balancing is subject to 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 cause 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 customer from correcting an imbalance which results in a penalty.

12. 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 12(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 12(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.

13. 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.

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

14. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper and/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 during the following day.

Customer's daily nomination shall be its best estimate of the expected utilization for the gas day. Unless other arrangements are made, customer will be required to nominate for the non-business days involved prior to weekends and holidays.

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

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

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

15. WARRANTY - 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 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.

16. 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, customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. The Company may remove such facilities when service hereunder is terminated.

17. 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 Rate 100, §V.13, or any amendments or alterations thereto.

18. 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.

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

20. RULES - The foregoing schedule is subject to Rates 100 -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 and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas requirements 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 treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement. The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge:	$567.25 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$0.582 per dk	$0.050 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.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88
3. Universal System Benefits Charge Rate 89

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. Customers taking service hereunder agree that the Company, without prior notice, shall have the right to curtail or interrupt such service whenever, in the 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 Rate 100, §V.10.

2. STANDBY REQUIREMENTS:
   a. If Company-approved equipment and fuel for standby service is not installed and maintained, the Company, in its discretion, may install automatic shut-off equipment in order to allow for the interruption of natural gas supply. The cost of the equipment and its installation shall be paid for by customer. The cost shall be the current market price for such equipment including the current installation costs. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

b. Customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of automatic shut-off equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

c. Customer's firm load must be separately metered if Company-approved equipment and fuel for standby service is not installed and maintained.

3. 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 the 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.

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

LARGE INTERRUPTIBLE GENERAL GAS SERVICE
Rate 85

5. OBLIGATION TO NOTIFY THE COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify the 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 customer equal to the penalty amounts the Company must pay to the interconnecting pipeline caused by customer's action.

6. 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.

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

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

GAS TAX TRACKING ADJUSTMENT Rate 87

1. **Applicability:**
This rate schedule sets forth the procedure to be used in calculating the Tax Tracking Adjustment in order to reflect: (a) changes in Montana-Dakota's Montana – state and local taxes and fees, and (b) a true-up of taxes recovered to actual taxes paid. The tax adjustment shall be shown as a separate item on the bill.

2. **Effective Date:**
The effective date of the Tax Tracking Adjustment shall be service rendered on and after January 1 each year.

3. **Tax Tracking Adjustment:**
   a. The Tax Tracking Adjustment shall reflect changes in Montana-Dakota's Montana state and local taxes and fees as compared to the base levels approved in its most recent general rate case. The difference to be included in the Tax Tracking Adjustment shall be net of income taxes.

   b. Base Tax – A base tax amount shall be established and updated in a general rate case for each rate schedule:
      (1) The ratio of authorized Montana state and local taxes and fees, excluding tribal taxes, to the total distribution revenues authorized in the rate case shall be determined.

      (2) The ratio is applied to the total basic service charge and distribution delivery charge revenues for each rate schedule to derive the base tax amount for each rate schedule.

   c. Rates excluding taxes
      (1) The authorized margin excluding base taxes (defined as base margin) is established by applying the ratio derived in 3.b.(1) to the authorized distribution revenues by rate schedule.

      (2) The percentage of taxes to base margin is derived to establish the basic service charge and distribution delivery charge amounts excluding the base

tax amount by applying the percentage to each rate component of each rate schedule.

d. The Tax Tracking Adjustment shall be computed as follows:
   (1) Tax expense for the year is compared to the tax expense recovered, including the tax related revenue from the conservation tracking adjustment lost margin with the difference net of income taxes determined.

   (2) A true-up of the prior year's adjustment for:
      i. Actual tax expense less actual tax recovery (adjusted for income taxes).
      ii. Tax expense less tax recovery included in the filing.
      iii. The net of 3.d.(2)i. and 3.2.(2)ii. is calculated and adjusted to exclude income taxes.

   (3) The sum of amounts in 3.d.(1) and 3.d.(2) above is divided by the base margin to derive the percent increase (decrease) in taxes.

   (4) The base tax percentage determined in 3.c.(2) and the tax adjustment percentage determined in 3.d.(3) are added to calculate the total percent of taxes.

   (5) The total percent of taxes is applied to the basic service charge and distribution delivery charge billed to each customer, and shown separately on the customer bill.

4. Time and Manner of Filing:
Each filing shall be made on or before the effective date of the adjustment, accompanied by the detailed computations which clearly show the derivation of the relevant amounts.

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

GAS TAX TRACKING ADJUSTMENT Rate 87

5. Tax Tracking Adjustment:

Base	25.3507%
Adjustment	(2.6807%)
Total tax	22.6700%

GAS COST TRACKING ADJUSTMENT PROCEDURE
Rate 88

1. **Applicability:**
This rate schedule sets forth the procedure to be used in calculating Gas Cost Tracking Adjustments. It specifies the procedure to be utilized to adjust the rates for gas sold under Montana-Dakota's rate schedules in the state of Montana in order to reflect: (a) changes in Montana-Dakota's average cost of gas supply and (b) amortization of the Unreflected Purchased Gas Cost Account.

2. **Effective Date and Limitation on Adjustments:**
   a. Unless otherwise ordered by the Commission, the effective dates of the gas cost tracking adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Unreflected Purchased Gas Cost Account shall be October 1 of each year.

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

3. **Minimum Filing Requirements:**
Montana-Dakota's filing to implement the Gas Cost Tracking Adjustment effective October 1 of each year shall include the following:

   a. Billing determinants by service agreement by month by supply source, with annual totals;

   b. Rates applicable to those billing determinants;

   c. Purchased gas costs by service agreement by month by supply source, with annual totals;

d. A list of FERC proceedings in which Montana-Dakota has participated with a brief description of the purpose of each and position taken by Montana-Dakota;

e. Total Montana-Dakota sales by major customer class by month with annual totals;

f. Montana-Dakota sales by major customer class by jurisdiction by month, with annual totals;

g. If Montana-Dakota has executed a new direct purchase contract since the last October 1 Gas Cost Tracking Adjustment, a description of what efforts, if any, were undertaken to ensure that the contract had pricing provisions which assured a firm supply of gas at a competitive price over the full term of the contract;

h. A description of what efforts, if any, Montana-Dakota has undertaken since the last October 1 Gas Cost Tracking Adjustment to utilize spot gas.

4. Gas Cost Tracking Adjustment:

a. The monthly Gas Cost Tracking Adjustment shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent Gas Cost Tracking Adjustment. 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. Any extraordinary costs, such as penalty charges and take-or-pay charges, shall be clearly identified as such and separately described in a supporting exhibit.

b. The Gas Cost Tracking Adjustment 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 gas cost tracking adjustment will be in effect and annual dk requirements.

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 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 dk's sold in each state, regardless of the actual points of delivery of such gas.

(5) All costs related to specific gas transportation services 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 Gas Cost Tracking Adjustment 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.

5. **Unreflected Gas Cost Adjustment:**
All sales rate schedules shall be subject to an Unreflected Gas Cost Adjustment to be effective on October 1 of each year. The Unreflected Gas Cost Adjustment per dk sold shall reflect amortization of the applicable balance in the Unreflected 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.

6. **Unreflected Purchased Gas Cost Account:**
a. Items to be included in the Unreflected Purchased Gas Cost Account, as calculated in accordance with Subsection 6(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in a Gas Cost Tracking Adjustment by reason of the twenty-five (25) cent minimum limitation set forth in Subsection 2(b).

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

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

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

b. The amount to be included in the Unreflected Purchased Gas Cost Account in order to reflect the items specified in Subsections 6(a)(1), (2), and (3) shall be calculated as follows:

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

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

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

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

c. Reduction of Amounts in the Unreflected Purchased Gas Cost Account:

(1) The amounts in the Unreflected Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective unreflected gas cost adjustment included in rates for that month (as calculated in Section 5) by the dk's sold during that month under each rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. Time and Manner of Filing:

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

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

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

UNIVERSAL SYSTEM BENEFITS CHARGE Rate 89

Applicability:

In all communities served for all end use sales and transportation service customers for funding of Universal System Benefits (USB) Programs.

Rate:

Charge per dk:

Sales Service Schedules (Rates 60, 70, 71, 72, 74, and 85)	$.0655
Transportation Service Schedules (Rates 81 and 82)	$.0028

Tracking Mechanism:

The rate above shall be subject to adjustment on an annual basis to be effective on May 1. The adjustment shall reflect the true up of actual expenditures associated with approved USB Programs and any adjustments necessary to provide funding at a target level of 0.48% of the prior year's total revenues. A filing to effectuate the May 1 change shall be made by March 1 of each year.

General Terms and Conditions:

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

Issued: June 22, 2020

By: Travis R. Jacobson
Director - Regulatory Affairs

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Docket No. 2020.06.076

Service rendered on and after April 1, 2021

CONSERVATION PROGRAM TRACKING MECHANISM Rate 90

Applicability:

This rate schedule represents a Conservation Program Tracking Mechanism and specifies the procedure to be utilized to recover the costs of conservation programs, as authorized by the Commission, including the recovery of distribution delivery charge revenues reduced as a result of the conservation programs. Service provided under the Company's Residential Service Rate 60 and Firm General Service Rates 70 and 72 shall be subject to this tracking mechanism.

Conservation Program Tracker:

An adjustment per dk will be determined for each rate schedule subject to the Conservation Program Tracking Mechanism. Monthly bills beginning with bills issued on and after May 1, 2007 and each May 1 thereafter, will be adjusted by the application of the Conservation Tracking Adjustment rate indicated below. The rate will reflect the amortization of the conservation program costs including the dk savings associated with each measure implemented in the prior 12 month period. The currently authorized Distribution Delivery Charge will be applied to the dk savings to compute the reduction in Distribution Delivery revenues associated with the conservation programs. The total program costs including the lost distribution revenues will be amortized over projected volumes to be sold over the next 12 month period. Following the initial one-year term, and annually thereafter, the Conservation Program Tracker rate calculation shall include any over or under collection of revenue from the preceding twelve month recovery period.

Conservation Tracking Adjustment: $0.009 per dk

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CONDITIONS OF SERVICE 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 Montana 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 - Customer requesting the Company to provide service.

COMMISSION - The Public Service Commission of the State of Montana.

COMPANY - Montana-Dakota Utilities Co. (Montana-Dakota)

COMPANY'S OPERATING CONVENIENCE - The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of the Company's operations. This does not refer to 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.

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

DELIVERY POINT - The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of the 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 24 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 the Company.

NOMINATION - The daily dk volume of the 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. This includes any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

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

SHIPPER - The party with whom the Pipeline has entered into a service agreement with in order to provide transportation service.

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE - 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 customer desiring the service. The Company may refuse an applicant or terminate service to customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any person who uses gas service in the absence of an application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

   Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. 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 pursuant to Rate 100, §V.6.

2. SERVICE AVAILABILITY – Gas will normally be delivered at standard pressures of four or five ounces, dependent on the service area 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 and pressures required for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at the Company's sole discretion, the Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will 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 at all reasonable times (8:00 am to 5:00 pm Monday through Friday 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 incident to the service.

5. COMPANY PROPERTY - Customer 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 - Customer shall not disconnect, change connections, make connections or otherwise interfere with the Company's meters or other property or permit same to be done by other than the Company's authorized employees.

7. RELOCATED LINES - Where Company facilities are located on a public or private utility easement and there is a building encroachment over gas facilities

(Company-owned main, Company-owned service line or customer-owned service line) the customer shall be charged for the line re-location on the basis of actual costs incurred by the Company including any required easements.

8. NOTIFICATION OF LEAKS - Customer shall immediately notify the Company at its office of any escape of gas in or about customer's premises.

9. TERMINATION OF SERVICE - Customer is required to notify the Company, to prevent 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 the Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

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 or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same, except when such loss, injury or damage results from the negligence of the Company.

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

leased by 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 customer's premises, except loss, injuries or damages resulting from the negligence of the Company.

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

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

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

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

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

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 customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in 12 months unless there is a material change in 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: single private residences, single apartments, mobile homes with separate meters and auxiliary buildings on the same premise when used for residential purposes by the residential customer. 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, sorority and fraternity houses, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty salons, 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), customer will be billed under the predominate use policy. Under this policy, customer's combined service is billed under the rate (residential or nonresidential) applicable to the type of service which constitutes 50% or more of 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 under the nonresidential rates.

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

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

6. CONSUMER DEPOSITS - The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission Rules ARM 38.5.1101 through 38.5.1112.

a. The amount of such deposit for residential service shall not exceed one-sixth of the estimated annual billing. For nonresidential service, the amount of the applicant's deposit shall not exceed 25% of the applicant's estimated annual billing.

b. The Company shall accept in lieu of a cash deposit a contract signed by a guarantor, whereby the payment of a specified sum not to exceed an estimated one year bill shall be guaranteed. Such estimation shall be made at the time the service is established. Guarantee terms and conditions will be in accordance with Commission Rules ARM 38.5.1111 and 38.5.1112.

   Interest on deposits held shall be accrued at the rate set forth in Rate 100, §VI.3. Interest shall be computed from the time of deposit to the time of refund or of termination. Interest shall be credited to customer's account annually during the month of December.

   Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for 12 months, provided a prompt payment record, as defined in the Commission rules, has been established.

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

   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 to reflect the heating value of 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 a temperature base of 60 degrees Fahrenheit (60 F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., Copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AGA-3/NX-19, as amended, 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 or five ounces (depending on service area) per square inch gauge pressure plus local average atmospheric pressure.

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

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

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

11. 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.

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

13. LATE PAYMENT – Amounts billed for energy or transportation services will be considered past due if not paid by the due date shown on the bill.

    For residential customers, an amount equal to the percentage set forth in Rate 100, §VI.2 will be applied to any unpaid balance existing at the second subsequent billing date provided, however, that such amount shall not apply where a bill is in dispute, written payment schedule has been arranged and complied with, or where the Low Income Energy Assistance Program (LIEAP) is being utilized up to the point where the funds are exhausted and the recipient has full responsibility for the account. In the event of a breach of a written payment arrangement, an amount equal to the percentage set forth in Rate 100, §VI.2 of the total remaining unpaid balance shall apply beginning 60 days after the date of the last payment under the payment arrangement. Such amount shall also apply (where the LIEAP program was utilized) to the total remaining unpaid balance on all accounts beginning 60 days after the LIEAP program no longer applies to such account.

    For nonresidential customers, an amount equal to the percentage set forth in Rate 100, §VI.2 will be applied to any unpaid balance existing at the immediate subsequent billing date.

    All payments received will apply to 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 as set forth in Rate 100, §VI.1.b. will be collected by the Company for any check not honored by customer's financial institution for any reason.

15. MANUAL METER READING CHARGE – A charge as set forth in Rate 100, §V.1.k. will be assessed monthly for 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. Customers agree to contract for the manual reading of the meter for 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 usage fees or any sales, uses, franchise, or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

    The charges to be added to customer's service bills under this clause shall be limited to 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. Responding to fire and explosion calls.
        2. Investigating hazardous conditions on customer premises, such as gas leaks, odor complaints and combustion gas fumes.
        3. Maintenance or repair of Company-owned facilities on 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 regular business hours:
   1. Reconnecting service to an existing facility (cut-in) or disconnecting service (cut-out).
   2. Investigating high bills or inadequate service complaints.
   3. Locating underground Company facilities for contractors, builders, plumbers, etc.
   4. Investigating noisy meter complaint.
   5. Moving meter from inside to outside.

18. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS - For service requested by customers to be performed after the Company's normal business hours of 8:00 am to 5:00 pm Monday through Friday local time, a charge will be made for labor at the overtime service rate set forth in Rate 100, §VI.1.f. and material at retail prices.

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

    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.

19. NOTICE TO DISCONTINUE GAS SERVICE - Customers desiring to have their gas service discontinued shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, or telephone call to the Company's Customer Service.

    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 for such installation in accordance with Rate 100, §VI.1.i.

21. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER - A customer who requests reconnection of service, at a location where same customer discontinued the same service during the preceding 12-month period will be charged 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 = 144 dk; Large Firm General = 1,122 dk; and Small Interruptible = 6,573 dk). A reconnection fee of $30.00 will also apply to reconnections. The minimum will be based on standard over time 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 reconnection charge as set forth in Rate 100, §VI.1.e. whenever reinstallation of the required remote data acquisition equipment is necessary.

22. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS - All amounts billed for services are due when rendered and become delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission.

    The Company may collect a fee, as set forth in Rate 100, § VI.1.c., before restoring gas service which has been disconnected for non-payment of service bills. Customers that qualified for the Low Income Energy Assistance Program during the current LIEAP program year will be subject to a reconnection charge of $12.00.

    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. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS - The Company reserves the right to discontinue service for any of the following reasons:
    a. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

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

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

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

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

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

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

The Company may collect a reconnect fee, as set forth in Rate 100, § VI.1.c. 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 the Company's 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.

1. Examples of unauthorized use of service includes, but is not limited to the tampering or unauthorized reconnection by the following methods:
   a. Bypass piping around meter.
   b. Bypass piping installed in place of meter.
   c. Meter reversed.

d. Meter index disengaged or removed.
e. Service or equipment tampered with or piping connected ahead of meter.
f. Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
g. Gas being used after service has been discontinued by the Company.
h. 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.

2. In the event that there has been unauthorized use of service, customer shall be charged for:
   a. Time, material and transportation costs used in investigation or surveillance.
   b. Estimated charge for non-metered gas.
   c. On-premise time to correct situation.
   d. Any damage to Company property.
   e. 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.

3. 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:
   a. All delinquent bills, if any;
   b. The amount of any Company revenue loss attributable to said tampering;
   c. Expenses incurred by the Company in replacing or repairing the meter or other appliance, costs incurred in preparation of the bill, plus costs as outlined in Paragraph 2 above;
   d. Reconnection fee applicable; and

e. A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules ARM 38.5.1105.

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

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

* Cubic feet per hour

The deposit shall be refunded only if the meter is found to have an un-acceptable error of greater than or less than two percent, as defined in the Commission's regulations. In the case where a meter is replaced due to malfunction, a customer will be allowed one additional free meter test within 12 months, if requested by the customer.

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

27. RATES FOR SPECIAL PROVISIONS:
Rate 101 - Gas Meter Testing Program
Rate 119 - Interruptible Gas Service Extension Policy
Rate 120 - Firm Gas Service Extension Policy
Rate 124 - Replacement, Relocation and Repair of Gas Service Lines

VI. MISCELLANEOUS CHARGES

	Amount or Reference
1. Service Charges	
a. Consumer deposits	Rate 100, §V.6
b. Returned check	$30.00
c. Minimum reconnect charge after termination for nonpayment or other causes	
- During normal business hours	$30.00 ($12.00 for LIEAP)
- After normal business hours	standard overtime rates
d. Minimum reconnect charge applicable to seasonal or temporary customers	
- During normal business hours	$30.00 minimum
- After normal business hours (See Rate 100 §V.22.)	standard overtime rates
e. Reconnection charge applicable to transport customers when electronic metering must be reinstalled	$160.00
f. Service request after normal business hours	Materials & labor at standard overtime rate
g. Interruptible service main extension	Rate 119

h. Firm service main extension	Rate 120
i. Installation of temporary metering or service facilities	Materials & labor
j. Replacement, relocation and repair of gas service lines	Rate 124
k. Manual Meter Read Charge	$18.35 per month

	Per Month	Approx. Annual Percent
2. Late Payment Charges (on unpaid balance)	1%	12%
3. Interest on Consumer Deposits	0.5%	6%

GAS METER TESTING PROGRAM Rate 101

The policy of the Company for testing meters pursuant to ARM 38.5.2513 is as follows:

1. This policy shall not apply to meters larger than 650 cubic feet per hour or greater capacity. Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.

   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 Montana, North Dakota, South Dakota, and Wyoming.

2. New meters received from a manufacturer shall be subjected to testing on a random sample basis of five percent of the total received, but never less than five meters, and must be found satisfactory before the shipment is released for use. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or the shipment shall be returned to the manufacturer.

3. Meters removed from service because of damage, meters that do not pass gas or that pass gas but do not register, and meters that are otherwise suspect as to accuracy, shall be tested and adjusted before reinstallation.

4. 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.

   a. 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 No. 414 for inspection by variables, inspection level IV with specification limits of +2.0 percent.

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

GAS METER TESTING PROGRAM Rate 101

b. 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.

5. 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 percent as follows:

   a. A meter lot 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 percent of the sample registers over 102 percent.

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

      i. If evaluation determines the group is homogeneous, 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 will be removed from service for testing and repair within one year.

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

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 (excluding remote data 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. Such tax amount will be calculated in accordance with the provisions of the Commission's Order in Docket No. 86.11.62, Order No. 5236(f).

   b. The contribution shall be made by:

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

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

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

INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

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

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

2. Refund

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

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

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

iii. No refunds will be made for amounts less than $25.

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

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

FIRM GAS SERVICE EXTENSION POLICY
Rate 120

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

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

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

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

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

   Maximum Allowable Investment =

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

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.

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. <u>Customer Extensions</u>

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

1. Contribution -

   a. When a contribution is required, the customer(s) shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with paragraph A.3., plus an amount for applicable federal and state income taxes. Such tax amount will be calculated in accordance with the provisions of the Commission's Order in Docket No. 86.11.62, Order No. 5236(f).

b. The contribution shall be made by:

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

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

   iii. Customer may post a bond or 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, letter of credit, or written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement, or

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

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

d. If within the five-year period from the extension(s) in-service date, the number of active customers and related 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, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

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

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

3. Incremental Expansion Surcharge -

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

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

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

      iii. For projects that are not expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus a commodity charge designed to provide recovery of the contribution requirement in a 5-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 extension(s) such as a subdivision or mobile home court, in which a developer is installing roads, utilities, etc., before housing is built.

1. Contribution -

a. When a contribution is required, the developer shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with paragraph A.3., plus an amount for applicable federal and state income taxes. Such tax amount will be calculated in accordance with the Commission's Order in Docket No. 86.11.62, Order No. 5236(f).

b. The contribution shall be made by:

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

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

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

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

2. Refund -

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

b. The Company will refund to the developer the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Developers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

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

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.), customer shall be charged 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 for on a direct cost basis. If the damage was caused by independent contractors, not in the employ of 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. Reserved for Future Use

Montana-Dakota Utilities Co.
Montana Natural Gas Tariffs - Proposed

Appendix B

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Availability:

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

Rate:

Basic Service Charge: $0.55 per day

Distribution Delivery Charge: $1.408 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.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88
3. Universal System Benefits Charge Rate 89
4. Conservation Program Tracking Mechanism Rate 90

Low-Income Discount:

Customers qualifying for and receiving energy assistance through the Low Income Energy Assistance Program (LIEAP) administered by the State of Montana

Availability:

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

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$1.05 per day
Distribution Delivery Charge	$1.414 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$2.30 per day
Distribution Delivery Charge:	$1.383 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.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88

Montana-Dakota Utilities Co.
400 N 4th Street
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SMALL INTERRUPTIBLE GENERAL GAS SERVICE
Rate 71

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas fueled 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 treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$360.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$0.802 per dk	$0.101 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.

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

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

Rate:

For customers with meters rated under 500 cubic feet per hour	
Basic Service Charge:	$1.05 per day
Distribution Delivery Charge:	$1.414 per dk
For customers with meters rated over 500 cubic feet per hour	
Basic Service Charge:	$2.30 per day
Distribution Delivery Charge:	$1.383 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.

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	$1.05 per day
For customers with meters rated over 500 cubic feet per hour	$2.30 per day
Distribution Demand Charge:	$6.57 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.

Rate:

Basic Service Charge:

	Rate 81	Rate 82
	$360.00 per month	$750.00 per month

Transportation Charges:	Rate 81	Rate 82
Maximum Rate per dk	$0.802	$0.717
Minimum Rate per dk	$0.101	$0.050

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Universal System Benefits Charge Rate 89

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. Customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

2. REQUEST FOR GAS TRANSPORTATION SERVICE- To qualify for gas transportation service, 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.

LARGE INTERRUPTIBLE GENERAL GAS SERVICE
Rate 85

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas requirements 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 treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement. The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge:	$750.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$0.717 per dk	$0.050 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.

5. Tax Tracking Adjustment:

Base	18.4388%
Adjustment	0.0000%
Total tax	18.4388%

d. A list of FERC proceedings in which Montana-Dakota has participated with a brief description of the purpose of each and position taken by Montana-Dakota;

e. If Montana-Dakota has executed a new direct purchase contract since the last October 1 Gas Cost Tracking Adjustment, a description of what efforts, if any, were undertaken to ensure that the contract had pricing provisions which assured a firm supply of gas at a competitive price over the full term of the contract;

f. A description of what efforts, if any, Montana-Dakota has undertaken since the last October 1 Gas Cost Tracking Adjustment to utilize spot gas.

4. Gas Cost Tracking Adjustment:

a. The monthly Gas Cost Tracking Adjustment shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent Gas Cost Tracking Adjustment. 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. Any extraordinary costs, such as penalty charges and take-or-pay charges, shall be clearly identified as such and separately described in a supporting exhibit.

b. The Gas Cost Tracking Adjustment 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 gas cost tracking adjustment will be in effect and annual dk requirements.

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 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 dk's sold in each state, regardless of the actual points of delivery of such gas.

(5) All costs related to specific gas transportation services 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 Gas Cost Tracking Adjustment 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.

5. **Unreflected Gas Cost Adjustment:**
All sales rate schedules shall be subject to an Unreflected Gas Cost Adjustment to be effective on October 1 of each year. The Unreflected Gas Cost Adjustment per dk sold shall reflect amortization of the applicable balance in the Unreflected 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.

6. **Unreflected Purchased Gas Cost Account:**
   a. Items to be included in the Unreflected Purchased Gas Cost Account, as calculated in accordance with Subsection 6(b) are:

      (1) Charges for gas supply which Montana-Dakota is unable to reflect in a Gas Cost Tracking Adjustment by reason of the twenty-five (25) cent minimum limitation set forth in Subsection 2(b).

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

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

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

   b. The amount to be included in the Unreflected Purchased Gas Cost Account in order to reflect the items specified in Subsections 6(a)(1), (2), and (3) shall be calculated as follows:

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

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

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

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

c. Reduction of Amounts in the Unreflected Purchased Gas Cost Account:

(1) The amounts in the Unreflected Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective unreflected gas cost adjustment included in rates for that month (as calculated in Section 5) by the dk's sold during that month

under each rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. Time and Manner of Filing:

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

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

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CURTAILMENT - A reduction of transportation or retail natural gas service deemed necessary by the Company.

CUSTOMER - Any individual, partnership, corporation, firm, other organization or government agency supplied with service by the Company at one location and at one point of delivery unless otherwise expressly provided for 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 the 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 24 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 the Company.

NOMINATION - The daily dk volume of the 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. This includes any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

leased by 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.

a. In the event the Company needs to turn a customer's gas meter on, and a customer's equipment needs to be restarted, the customer may consent to, and accept responsibility for, the relighting of any pilot lights on equipment on customer's side of the meter. If verbal consent of customer is given at the time of scheduling the gas meter turn on, Company personnel will turn gas meter on and inspect for gas use. If no gas use is detected at that time, the gas meter will be left on and the customer can relight any pilot lights on equipment on customer's side of the meter at their convenience. If gas use is detected, Company personnel will turn gas meter off and advise customer to have their system checked. The Company will only turn the gas meter on after customer's system has been checked and no gas use is detected.

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 customer's premises, except loss, injuries or damages resulting from the negligence of the Company.

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

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

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

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

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 customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in 12 months unless there is a material change in 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: single private residences, single apartments, mobile homes with separate meters and auxiliary buildings on the same premise when used for residential purposes by the residential customer. 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, sorority and fraternity houses, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty salons, 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), customer will be billed under the predominate use policy. Under this policy, customer's combined service is billed under the rate (residential or nonresidential) applicable to the type of service which constitutes 50% or more of 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 under the nonresidential rates.

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

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES - The rules and regulations for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 -

Manufactured Home Construction and Safety Standards) Subparts G and H which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities. This information is available at Montana-Dakota Utilities Co.'s offices.

6. CONSUMER DEPOSITS - The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission Rules ARM 38.5.1101 through 38.5.1112.

   a. The amount of such deposit for residential service shall not exceed one-sixth of the estimated annual billing. For nonresidential service, the amount of the applicant's deposit shall not exceed 25% of the applicant's estimated annual billing.

   b. The Company shall accept in lieu of a cash deposit a contract signed by a guarantor, whereby the payment of a specified sum not to exceed an estimated one year bill shall be guaranteed. Such estimation shall be made at the time the service is established. Guarantee terms and conditions will be in accordance with Commission Rules ARM 38.5.1111 and 38.5.1112.

      Interest on deposits held shall be accrued at the rate set forth in Rate 100, §VI.3. Interest shall be computed from the time of deposit to the time of refund or of termination. Interest shall be credited to customer's account annually during the month of December.

      Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for 12 months, provided a prompt payment record, as defined in the Commission rules, has been established.

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

   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 to reflect the heating value of 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 a temperature base of 60 degrees Fahrenheit (60 F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where gas is delivered at 20 psig or more, the deviation of the natural gas from

Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., Copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AGA-3/NX-19, as amended, 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 or five ounces (depending on service area) per square inch gauge pressure plus local average atmospheric pressure.

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

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

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

11. 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.

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

13. LATE PAYMENT – Amounts billed for energy or transportation services will be considered past due if not paid by the due date shown on the bill.

    For residential customers, an amount equal to the percentage set forth in Rate 100, §VI.2 will be applied to any unpaid balance existing at the second subsequent billing date provided, however, that such amount shall not apply where a bill is in dispute, written payment schedule has been arranged and complied with, or where the Low Income Energy Assistance Program (LIEAP) is being utilized up to the point where the funds are exhausted and the recipient has full responsibility for the account. In the event of a breach of a written payment arrangement, an amount equal to the percentage set forth in Rate 100, §VI.2 of the total remaining unpaid balance shall apply beginning 60 days after the date of the last payment under the payment arrangement. Such amount shall also apply (where the LIEAP program was utilized) to the total remaining unpaid balance on all accounts beginning 60 days after the LIEAP program no longer applies to such account.

For nonresidential customers, an amount equal to the percentage set forth in Rate 100, §VI.2 will be applied to any unpaid balance existing at the immediate subsequent billing date.

All payments received will apply to 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 as set forth in Rate 100, §VI.1.b. will be collected by the Company for any check not honored by customer's financial institution for any reason.

15. MANUAL METER READING CHARGE – A charge as set forth in Rate 100, §V.1.k. will be assessed monthly for 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. Customers agree to contract for the manual reading of the meter for 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 usage fees or any sales, uses, franchise, or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

The charges to be added to customer's service bills under this clause shall be limited to 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. Responding to fire and explosion calls.
        2. Investigating hazardous conditions on customer premises, such as gas leaks, odor complaints and combustion gas fumes.
        3. Maintenance or repair of Company-owned facilities on 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 regular business hours:
        1. Reconnecting service to an existing facility (cut-in) or disconnecting service (cut-out).
        2. Investigating high bills or inadequate service complaints.
        3. Locating underground Company facilities for contractors, builders, plumbers, etc.
        4. Investigating noisy meter complaint.
        5. Moving meter from inside to outside.

18. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS - For service requested by customers to be performed after the Company's normal business hours of 8:00 am to 5:00 pm Monday through Friday local time, a charge will be made for labor at the overtime service rate set forth in Rate 100, §VI.1.f. and material at retail prices.

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

To ensure the Company can service the customer during normal business hours, the customer’s call must be received by 12:00 p.m. local time on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. local time 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.

19. NOTICE TO DISCONTINUE GAS SERVICE - Customers desiring to have their gas service discontinued shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, or telephone call to the Company's Customer Service.

    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 for such installation in accordance with Rate 100, §VI.1.i.

21. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER - A customer who requests reconnection of service, at a location where same customer discontinued the same service during the preceding 12-month period will be charged 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 = 143 dk; Large Firm General = 1,110 dk; and Small Interruptible = 12,112 dk). A reconnection fee of $30.00 will also apply to reconnections. The minimum will be based on standard over time 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 reconnection charge as set forth in Rate 100, §VI.1.e. whenever reinstallation of the required remote data acquisition equipment is necessary.

22. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS - All amounts billed for services are due when rendered and become delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission.

    The Company may collect a fee, as set forth in Rate 100, § VI.1.c., before restoring gas service which has been disconnected for non-payment of service bills. Customers that qualified for the Low Income Energy Assistance Program during the current LIEAP program year will be subject to a reconnection charge of $12.00.

    For calls received after 12:00 p.m. local time 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. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS - The Company reserves the right to discontinue service for any of the following reasons:

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

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

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

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

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

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

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

   The Company may collect a reconnect fee, as set forth in Rate 100, § VI.1.c. 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 the Company's 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.

1. Examples of unauthorized use of service includes, but is not limited to the tampering or unauthorized reconnection by the following methods:
   a. Bypass piping around meter.
   b. Bypass piping installed in place of meter.
   c. Meter reversed.
   d. Meter index disengaged or removed.
   e. Service or equipment tampered with or piping connected ahead of meter.
   f. Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
   g. Gas being used after service has been discontinued by the Company.
   h. 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.

2. In the event that there has been unauthorized use of service, customer shall be charged for:
   a. Time, material and transportation costs used in investigation or surveillance.
   b. Estimated charge for non-metered gas.
   c. On-premise time to correct situation.
   d. Any damage to Company property.
   e. 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.

3. 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:
   a. All delinquent bills, if any;
   b. The amount of any Company revenue loss attributable to said tampering;
   c. Expenses incurred by the Company in replacing or repairing the meter or other appliance, costs incurred in preparation of the bill, plus costs as outlined in Paragraph 2 above;
   d. Reconnection fee applicable; and
   e. A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules ARM 38.5.1105.

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

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

* Cubic feet per hour

The deposit shall be refunded only if the meter is found to have an unacceptable error of greater than or less than two percent, as defined in the Commission's regulations. In the case where a meter is replaced due to malfunction, a customer will be allowed one additional free meter test within 12 months, if requested by the customer.

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

27. RATES FOR SPECIAL PROVISIONS:
Rate 101 - Gas Meter Testing Program
Rate 119 - Interruptible Gas Service Extension Policy
Rate 120 - Firm Gas Service Extension Policy
Rate 124 - Replacement, Relocation and Repair of Gas Service Lines

VI. MISCELLANEOUS CHARGES	Amount or Reference
1. Service Charges	
a. Consumer deposits	Rate 100, §V.6
b. Returned check	$30.00
c. Minimum reconnect charge after termination for nonpayment or other causes	
- During normal business hours	$30.00 ($12.00 for LIEAP)
- After normal business hours	standard overtime rates

d.	Minimum reconnect charge applicable to seasonal or temporary customers - During normal business hours - After normal business hours (See Rate 100 §V.22.)	$30.00 minimum standard overtime rates	
e.	Reconnection charge applicable to transport customers when electronic metering must be reinstalled	$160.00	
f.	Service request after normal business hours	Materials & labor at standard overtime rate	
g.	Interruptible service main extension	Rate 119	
h.	Firm service main extension	Rate 120	
i.	Installation of temporary metering or service facilities	Materials & labor	
j.	Replacement, relocation and repair of gas service lines	Rate 124	
k.	Manual Meter Read Charge	$18.35 per month	

		Per Month	Approx. Annual Percent
2.	Late Payment Charges (on unpaid balance)	1%	12%
3.	Interest on Consumer Deposits	0.5%	6%

GAS METER TESTING PROGRAM Rate 101

The policy of the Company for testing meters pursuant to ARM 38.5.2513 is as follows:

1. This policy shall not apply to meters larger than 650 cubic feet per hour or greater capacity. Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.

   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 Montana, Minnesota, North Dakota, South Dakota, and Wyoming.

2. New meters received from a manufacturer shall be subjected to testing on a random sample basis of five percent of the total received, but never less than five meters, and must be found satisfactory before the shipment is released for use. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or the shipment shall be returned to the manufacturer.

3. Meters removed from service because of damage, meters that do not pass gas or that pass gas but do not register, and meters that are otherwise suspect as to accuracy, shall be tested and adjusted before reinstallation.

4. 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.

   a. 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 No. 414 for inspection by variables, inspection level IV with specification limits of +2.0 percent.

SUMMARY BILLING PLAN Rate 115

Availability:

Under the Company's Summary Billing Plan, customers are provided an optional billing arrangement under which a customer's multiple premises may be consolidated into one billing statement each month. This billing arrangement is available in all communities served by the Company for customers who voluntarily agree to participate in the Summary Billing Plan and who continue to meet the availability and terms and conditions of the plan.

The Company may limit the number of premises participating in the plan and exclude services based on rate and/or customer class or credit standing with the Company. Seasonal, short-term, or temporary customers will not be allowed to enroll. Participation in other optional programs such as Balanced Billing may also limit a customer's ability to participate in this billing arrangement. This is not an all-inclusive list of exclusions and service enrollment is at the Company's sole discretion.

General Terms and Conditions:

1. A customer requesting Summary Billing must provide 45 days advanced notice of their request to enroll.
2. Customer agrees to contract for Summary Billing for a minimum of one year.
3. Each service enrolled in the Summary Billing Plan shall be billed at the otherwise applicable rate schedule.
4. The Company, at its sole discretion, will select the bill date for an enrolled customer's Summary Bill.
5. Enrolled customers need only make one payment each month covering the total amount due for all services included in the Summary Bill.
6. Payment policies remain in effect for each customer participating in the plan. Any determination of delinquencies will be based on the bill date of the Summary Bill.

SUMMARY BILLING PLAN Rate 115

   a. If a customer participating in the Summary Billing Plan falls into arrears, the Company, at its sole discretion, may discontinue this optional billing arrangement and revert the services into separate billing statements.

7. Either the customer or the Company may cancel a customer's Summary Billing Plan with a 45-day advanced notice of cancellation. Upon cancellation of the plan, a customer's services will revert into separate billing statements.
   a. Upon cancellation of a Summary Billing Plan, the customer may not request the establishment of a new Summary Billing Plan for at least one year after cancellation.

8. The Company will not be liable for any customer costs which may result from any refusals, delays or failures resulting from requests for, or changes to, a customer's Summary Billing Plan.

Tariffs Reflecting Proposed Changes

Public Service Commission of Montana

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

Natural Gas Service

Volume No. 7
~~Original~~ 1st Revised Sheet No. 1
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Director – Regulatory Affairs

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~~Docket No. 2020.06.076~~ ~~Service rendered on and after April 1, 2021~~

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

RESIDENTIAL GAS SERVICE Rate 60

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

Rate:

Basic Service Charge: $~~0.30~~0.55 per day

Distribution Delivery Charge: $~~1.352~~1.408 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.

Adjustment Clauses:
Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88
3. Universal System Benefits Charge Rate 89
4. Conservation Program Tracking Mechanism Rate 90

Low-Income Discount:
Customers qualifying for and receiving energy assistance through the Low Income Energy Assistance Program (LIEAP) administered by the State of Montana

Public Service Commission of Montana

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

Natural Gas Service

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FIRM GENERAL GAS SERVICE Rate 70

Availability:

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

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$~~0.60~~1.05 per day
Distribution Delivery Charge	$~~1.577~~1.414 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$~~1.75~~2.30 per day
Distribution Delivery Charge:	$~~1.491~~1.383 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.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Gas Cost Tracking Adjustment Procedure Rate 88

Issued: ~~February 26, 2021~~July 15, 2024

By: Travis R. Jacobson
Director - Regulatory Affairs

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

Natural Gas Service

Volume No. 7
~~Original~~ 1st Revised Sheet No. 22
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SMALL INTERRUPTIBLE GENERAL GAS SERVICE
Rate 71

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas fueled 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 treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$~~312.00~~360.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$~~0.794~~0.802 per dk	$0.101 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.

Issued: ~~February 26, 2021~~July 15, 2024 **By:** Travis R. Jacobson
Director - Regulatory Affairs

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~~Docket No. 2020.06.076~~ ~~Service rendered on and after April 1, 2021~~

Public Service Commission of Montana

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

Natural Gas Service

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

Availability:

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

Rate:

For customers with meters rated under 500 cubic feet per hour	
Basic Service Charge:	$~~0.60~~1.05 per day
Distribution Delivery Charge:	$~~1.5770~~1.414 per dk
For customers with meters rated over 500 cubic feet per hour	
Basic Service Charge:	$~~1.75~~2.30 per day
Distribution Delivery Charge:	$~~1.491~~1.383 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.

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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	$~~0.60~~1.05 per day
For customers with meters rated over 500 cubic feet per hour	$~~1.75~~2.30 per day
Distribution Demand Charge:	$~~4.89~~6.57 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.

Rate:

Basic Service Charge:

Rate 81	Rate 82
$~~312.00~~360.00 per month	$~~567.25~~750.00 per month

Transportation Charges:	Rate 81	Rate 82
Maximum Rate per dk	$~~0.794~~0.802	$~~0.582~~0.717
Minimum Rate per dk	$0.101	$0.050

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Gas Tax Tracking Adjustment Rate 87
2. Universal System Benefits Charge Rate 89

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. Customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

2. REQUEST FOR GAS TRANSPORTATION SERVICE- To qualify for gas transportation service, 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.

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

LARGE INTERRUPTIBLE GENERAL GAS SERVICE
Rate 85

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas requirements 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 treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement. The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge:	$~~567.25~~750.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$~~0.582~~0.717 per dk	$0.050 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.

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

Natural Gas Service

Volume No. 7
~~3rd~~ 4th Revised Sheet No. 36.2
Canceling ~~2nd~~ 3rd Revised Sheet No. 36.2

GAS TAX TRACKING ADJUSTMENT Rate 87

5. Tax Tracking Adjustment:

Base	~~25.3507~~18.4388%
Adjustment	~~(2.6807%)~~0.0000%
Total tax	~~22.6700~~18.4388%

d. A list of FERC proceedings in which Montana-Dakota has participated with a brief description of the purpose of each and position taken by Montana-Dakota;

~~e. Total Montana-Dakota sales by major customer class by month with annual totals;~~

~~f. Montana-Dakota sales by major customer class by jurisdiction by month, with annual totals;~~

~~g.~~e. If Montana-Dakota has executed a new direct purchase contract since the last October 1 Gas Cost Tracking Adjustment, a description of what efforts, if any, were undertaken to ensure that the contract had pricing provisions which assured a firm supply of gas at a competitive price over the full term of the contract;

~~h.~~f. A description of what efforts, if any, Montana-Dakota has undertaken since the last October 1 Gas Cost Tracking Adjustment to utilize spot gas.

4. Gas Cost Tracking Adjustment:

a. The monthly Gas Cost Tracking Adjustment shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent Gas Cost Tracking Adjustment. 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. Any extraordinary costs, such as penalty charges and take-or-pay charges, shall be clearly identified as such and separately described in a supporting exhibit.

b. The Gas Cost Tracking Adjustment 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 gas cost tracking adjustment will be in effect and annual dk requirements.

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 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 dk's sold in each state, regardless of the actual points of delivery of such gas.

(5) All costs related to specific gas transportation services 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 Gas Cost Tracking Adjustment 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.

5. **Unreflected Gas Cost Adjustment:**
All sales rate schedules shall be subject to an Unreflected Gas Cost Adjustment to be effective on October 1 of each year. The Unreflected Gas Cost Adjustment per dk sold shall reflect amortization of the applicable balance in the Unreflected 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.

6. **Unreflected Purchased Gas Cost Account:**
a. Items to be included in the Unreflected Purchased Gas Cost Account, as calculated in accordance with Subsection 6(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in a Gas Cost Tracking Adjustment by reason of the twenty-five (25) cent minimum limitation set forth in Subsection 2(b).

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

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

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

b. The amount to be included in the Unreflected Purchased Gas Cost Account in order to reflect the items specified in Subsections 6(a)(1), (2), and (3) shall be calculated as follows:

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

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

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

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

c. Reduction of Amounts in the Unreflected Purchased Gas Cost Account:

(1) The amounts in the Unreflected Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective unreflected gas cost adjustment included in rates for that month (as calculated in Section 5) by the dk's sold during that month under each rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. Time and Manner of Filing:

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

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

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CURTAILMENT - A reduction of transportation or retail natural gas service deemed necessary by the Company.

CUSTOMER - Any individual, partnership, corporation, firm, other organization or government agency supplied with service by the Company at one location and at one point of delivery unless otherwise expressly provided for 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 the 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 24 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 the Company.

NOMINATION - The daily dk volume of the 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. This includes any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

leased by 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.

a. In the event the Company needs to turn a customer's gas meter on, and a customer's equipment needs to be restarted, the customer may consent to, and accept responsibility for, the relighting of any pilot lights on equipment on customer's side of the meter. If verbal consent of customer is given at the time of scheduling the gas meter turn on, Company personnel will turn gas meter on and inspect for gas use. If no gas use is detected at that time, the gas meter will be left on and the customer can relight any pilot lights on equipment on customer's side of the meter at their convenience. If gas use is detected, Company personnel will turn gas meter off and advise customer to have their system checked. The Company will only turn the gas meter on after customer's system has been checked and no gas use is detected.

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 customer's premises, except loss, injuries or damages resulting from the negligence of the Company.

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

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

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

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

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

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 customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in 12 months unless there is a material change in 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: single private residences, single apartments, mobile homes with separate meters and auxiliary buildings on the same premise when used for residential purposes by the residential customer. 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, sorority and fraternity houses, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty salons, 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), customer will be billed under the predominate use policy. Under this policy, customer's combined service is billed under the rate (residential or nonresidential) applicable to the type of service which constitutes 50% or more of 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 under the nonresidential rates.

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

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

6. CONSUMER DEPOSITS - The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission Rules ARM 38.5.1101 through 38.5.1112.

a. The amount of such deposit for residential service shall not exceed one-sixth of the estimated annual billing. For nonresidential service, the amount of the applicant's deposit shall not exceed 25% of the applicant's estimated annual billing.

b. The Company shall accept in lieu of a cash deposit a contract signed by a guarantor, whereby the payment of a specified sum not to exceed an estimated one year bill shall be guaranteed. Such estimation shall be made at the time the service is established. Guarantee terms and conditions will be in accordance with Commission Rules ARM 38.5.1111 and 38.5.1112.

Interest on deposits held shall be accrued at the rate set forth in Rate 100, §VI.3. Interest shall be computed from the time of deposit to the time of refund or of termination. Interest shall be credited to customer's account annually during the month of December.

Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for 12 months, provided a prompt payment record, as defined in the Commission rules, has been established.

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

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 to reflect the heating value of 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 a temperature base of 60 degrees Fahrenheit (60 F). All measurement of natural gas by orifice meter shall be reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., Copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AGA-3/NX-19, as amended, 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 or five ounces (depending on service area) per square inch gauge pressure plus local average atmospheric pressure.

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

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

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

11. 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.

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

13. LATE PAYMENT – Amounts billed for energy or transportation services will be considered past due if not paid by the due date shown on the bill.

    For residential customers, an amount equal to the percentage set forth in Rate 100, §VI.2 will be applied to any unpaid balance existing at the second subsequent billing date provided, however, that such amount shall not apply where a bill is in dispute, written payment schedule has been arranged and complied with, or where the Low Income Energy Assistance Program (LIEAP) is being utilized up to the point where the funds are exhausted and the recipient has full responsibility for the account. In the event of a breach of a written payment arrangement, an amount equal to the percentage set forth in Rate 100, §VI.2 of the total remaining unpaid balance shall apply beginning 60 days after the date of the last payment under the payment arrangement. Such amount shall also apply (where the LIEAP program was utilized) to the total remaining unpaid balance on all accounts beginning 60 days after the LIEAP program no longer applies to such account.

    For nonresidential customers, an amount equal to the percentage set forth in Rate 100, §VI.2 will be applied to any unpaid balance existing at the immediate subsequent billing date.

    All payments received will apply to 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 as set forth in Rate 100, §VI.1.b. will be collected by the Company for any check not honored by customer's financial institution for any reason.

15. MANUAL METER READING CHARGE – A charge as set forth in Rate 100, §V.1.k. will be assessed monthly for 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. Customers agree to contract for the manual reading of the meter for 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 usage fees or any sales, uses, franchise, or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

    The charges to be added to customer's service bills under this clause shall be limited to 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. Responding to fire and explosion calls.
        2. Investigating hazardous conditions on customer premises, such as gas leaks, odor complaints and combustion gas fumes.
        3. Maintenance or repair of Company-owned facilities on 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 regular business hours:
   1. Reconnecting service to an existing facility (cut-in) or disconnecting service (cut-out).
   2. Investigating high bills or inadequate service complaints.
   3. Locating underground Company facilities for contractors, builders, plumbers, etc.
   4. Investigating noisy meter complaint.
   5. Moving meter from inside to outside.

18. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS - For service requested by customers to be performed after the Company's normal business hours of 8:00 am to 5:00 pm Monday through Friday local time, a charge will be made for labor at the overtime service rate set forth in Rate 100, §VI.1.f. and material at retail prices.

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

    To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. local time on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. local time 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.

19. NOTICE TO DISCONTINUE GAS SERVICE - Customers desiring to have their gas service discontinued shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, or telephone call to the Company's Customer Service.

    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 for such installation in accordance with Rate 100, §VI.1.i.

21. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER - A customer who requests reconnection of service, at a location where same customer discontinued the same service during the preceding 12-month period will be charged 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 = ~~144~~143 dk; Large Firm General = ~~1,122~~1,110 dk; and Small Interruptible = ~~6,573~~12,112 dk). A reconnection fee of $30.00 will also apply to reconnections. The minimum will be based on standard over time 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 reconnection charge as set forth in Rate 100, §VI.1.e. whenever reinstallation of the required remote data acquisition equipment is necessary.

22. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS - All amounts billed for services are due when rendered and become delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission.

    The Company may collect a fee, as set forth in Rate 100, § VI.1.c., before restoring gas service which has been disconnected for non-payment of service bills. Customers that qualified for the Low Income Energy Assistance Program during the current LIEAP program year will be subject to a reconnection charge of $12.00.

    For calls received after 12:00 p.m. local time 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. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS - The Company reserves the right to discontinue service for any of the following reasons:
    a. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

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

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

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

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

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

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

The Company may collect a reconnect fee, as set forth in Rate 100, § VI.1.c. 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 the Company's 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.

1. Examples of unauthorized use of service includes, but is not limited to the tampering or unauthorized reconnection by the following methods:
   a. Bypass piping around meter.
   b. Bypass piping installed in place of meter.
   c. Meter reversed.

d. Meter index disengaged or removed.
e. Service or equipment tampered with or piping connected ahead of meter.
f. Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
g. Gas being used after service has been discontinued by the Company.
h. 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.

2. In the event that there has been unauthorized use of service, customer shall be charged for:
   a. Time, material and transportation costs used in investigation or surveillance.
   b. Estimated charge for non-metered gas.
   c. On-premise time to correct situation.
   d. Any damage to Company property.
   e. 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.

3. 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:
   a. All delinquent bills, if any;
   b. The amount of any Company revenue loss attributable to said tampering;
   c. Expenses incurred by the Company in replacing or repairing the meter or other appliance, costs incurred in preparation of the bill, plus costs as outlined in Paragraph 2 above;
   d. Reconnection fee applicable; and

e. A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules ARM 38.5.1105.

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

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

* Cubic feet per hour

The deposit shall be refunded only if the meter is found to have an un-acceptable error of greater than or less than two percent, as defined in the Commission's regulations. In the case where a meter is replaced due to malfunction, a customer will be allowed one additional free meter test within 12 months, if requested by the customer.

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

27. RATES FOR SPECIAL PROVISIONS:
Rate 101 - Gas Meter Testing Program
Rate 119 - Interruptible Gas Service Extension Policy
Rate 120 - Firm Gas Service Extension Policy
Rate 124 - Replacement, Relocation and Repair of Gas Service Lines

VI. MISCELLANEOUS CHARGES

	Amount or Reference
1. Service Charges	
a. Consumer deposits	Rate 100, §V.6
b. Returned check	$30.00
c. Minimum reconnect charge after termination for nonpayment or other causes	
- During normal business hours	$30.00 ($12.00 for LIEAP)
- After normal business hours	standard overtime rates
d. Minimum reconnect charge applicable to seasonal or temporary customers	
- During normal business hours	$30.00 minimum
- After normal business hours (See Rate 100 §V.22.)	standard overtime rates
e. Reconnection charge applicable to transport customers when electronic metering must be reinstalled	$160.00
f. Service request after normal business hours	Materials & labor at standard overtime rate
g. Interruptible service main extension	Rate 119

h.	Firm service main extension	Rate 120
i.	Installation of temporary metering or service facilities	Materials & labor
j.	Replacement, relocation and repair of gas service lines	Rate 124
k.	Manual Meter Read Charge	$18.35 per month

	Per Month	Approx. Annual Percent
2. Late Payment Charges (on unpaid balance)	1%	12%
3. Interest on Consumer Deposits	0.5%	6%

The policy of the Company for testing meters pursuant to ARM 38.5.2513 is as follows:

1. This policy shall not apply to meters larger than 650 cubic feet per hour or greater capacity. Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.

   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 Montana, Minnesota, North Dakota, South Dakota, and Wyoming.

2. New meters received from a manufacturer shall be subjected to testing on a random sample basis of five percent of the total received, but never less than five meters, and must be found satisfactory before the shipment is released for use. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or the shipment shall be returned to the manufacturer.

3. Meters removed from service because of damage, meters that do not pass gas or that pass gas but do not register, and meters that are otherwise suspect as to accuracy, shall be tested and adjusted before reinstallation.

4. 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.

   a. 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 No. 414 for inspection by variables, inspection level IV with specification limits of +2.0 percent.

SUMMARY BILLING PLAN Rate 115

Availability:

Under the Company's Summary Billing Plan, customers are provided an optional billing arrangement under which a customer's multiple premises may be consolidated into one billing statement each month. This billing arrangement is available in all communities served by the Company for customers who voluntarily agree to participate in the Summary Billing Plan and who continue to meet the availability and terms and conditions of the plan.

The Company may limit the number of premises participating in the plan and exclude services based on rate and/or customer class or credit standing with the Company. Seasonal, short-term, or temporary customers will not be allowed to enroll. Participation in other optional programs such as Balanced Billing may also limit a customer's ability to participate in this billing arrangement. This is not an all-inclusive list of exclusions and service enrollment is at the Company's sole discretion.

General Terms and Conditions:

1. A customer requesting Summary Billing must provide 45 days advanced notice of their request to enroll.

2. Customer agrees to contract for Summary Billing for a minimum of one year.

3. Each service enrolled in the Summary Billing Plan shall be billed at the otherwise applicable rate schedule.

4. The Company, at its sole discretion, will select the bill date for an enrolled customer's Summary Bill.

5. Enrolled customers need only make one payment each month covering the total amount due for all services included in the Summary Bill.

6. Payment policies remain in effect for each customer participating in the plan. Any determination of delinquencies will be based on the bill date of the Summary Bill.

SUMMARY BILLING PLAN Rate 115

a. If a customer participating in the Summary Billing Plan falls into arrears, the Company, at its sole discretion, may discontinue this optional billing arrangement and revert the services into separate billing statements.

7. Either the customer or the Company may cancel a customer's Summary Billing Plan with a 45-day advanced notice of cancellation. Upon cancellation of the plan, a customer's services will revert into separate billing statements.
   a. Upon cancellation of a Summary Billing Plan, the customer may not request the establishment of a new Summary Billing Plan for at least one year after cancellation.

8. The Company will not be liable for any customer costs which may result from any refusals, delays or failures resulting from requests for, or changes to, a customer's Summary Billing Plan.

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2024.05.061

Direct Testimony

Of

Nicole A. Kivisto

Q. **Please state your name and business address.**

A. My name is Nicole A. Kivisto, and my business address is 1200 West Century Avenue, Bismarck, North Dakota 58506.

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

A. I am the President and Chief Executive Officer (CEO) of MDU Resources Group, Inc. (MDU Resources). I also continue to serve as President and CEO of Montana-Dakota Utilities Co. (Montana-Dakota or Company), Cascade Natural Gas Corporation, and Intermountain Gas Company are subsidiaries. These subsidiaries, combined with Great Plains Natural Gas Co. (Great Plains), a division of Montana-Dakota, are collectively referred to as the MDU Utilities Group.

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

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 1.2 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 2024. I was the President and CEO of Montana-Dakota, Cascade Natural Gas Corporation, Intermountain Gas Company, and Great Plains from January 2015 until also assuming my present position in January 2024.

Prior to that I was the Vice President-Operations of Montana-Dakota and Great Plains for one year. Before 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 North Dakota and Wyoming, the Public Utilities Commissions of Idaho, South Dakota, and Minnesota, 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 Montana-Dakota's gas operations in the state of Montana. I will also provide an overview of the Company's request for a gas 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 who will present testimony and exhibits in further support of the Company's request.

Q. Please provide a summary of Montana-Dakota's gas operations in Montana.

A. Montana-Dakota provides natural gas service to approximately 88,900 customers in 30 communities in Montana, operating approximately 1,822 miles of distribution mains and approximately 1,495 miles of service lines. The customer base is 88 percent residential and 12 percent commercial and industrial. As of December 31, 2023, the Company had 137 full and part-time employees who live and work throughout our Montana electric and gas service area.

Montana-Dakota's Montana gas service area is divided into two operating regions with regional offices located in Billings, Montana and Dickinson, North Dakota and a number of smaller district offices located in communities throughout Montana.

Montana-Dakota's customers have toll-free access to the Customer Experience Team and the Credit Center 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, 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. Please provide more information regarding the customers the Company serves.

A. The residential, firm general service, and small interruptible customers use natural gas primarily for space and water heating. As such, Montana-Dakota's system has a low load factor with peak gas requirements occurring during the winter. Summer loads are small by comparison. Montana-Dakota is projecting to deliver approximately 14.1 MMdk of natural gas to customers in Montana in 2024. The natural gas requirements by customer class is as follows: approximately 43 percent residential, 30 percent firm general service, 6 percent small interruptible, and 21 percent large interruptible.

Q. 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. These gas costs are passed on to customers on a dollar-for-dollar basis as specified in the Commission approved Purchased Gas Cost Adjustment tariff. The gas portion of the cost of providing natural gas service currently comprises about 58 percent of a typical residential bill for gas service.

The distribution cost 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 42 percent of a typical residential bill.

Q. Ms. Kivisto, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

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

A. Montana-Dakota is requesting an increase in its gas rates because our current rates do not reflect the cost of providing natural gas service to Montana-Dakota's Montana customers. For the twelve months ending December 31, 2023, the Company's Rate of Return was 2.600 percent.

This is below the last authorized Rate of Return of 7.208 percent in Docket No. D2017.9.79.

Q. When was the Company's last general rate case?

A. The Company's last rate case was Docket No. 2020.06.076, which resulted in an increase of $7.25 million or an 11.37 percent overall increase. Final rates in the case became effective on and after April 1, 2021.

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting $9,400,268 which represents an 11.1 percent increase based on a 2023 test year adjusted for known and measurable changes. This increase represents an average yearly increase of 2.8 percent per year.

Q. How would this increase affect the Company's residential customers?

A. The Company's residential class of customers would see an increase of 16.4 percent, or an increase of approximately 4 percent per year. As a result, an individual residential customer using 6.5 Dk per month will see an increase of approximately $8.68 per month.

Q. Can you briefly explain the additional revenue requirement?

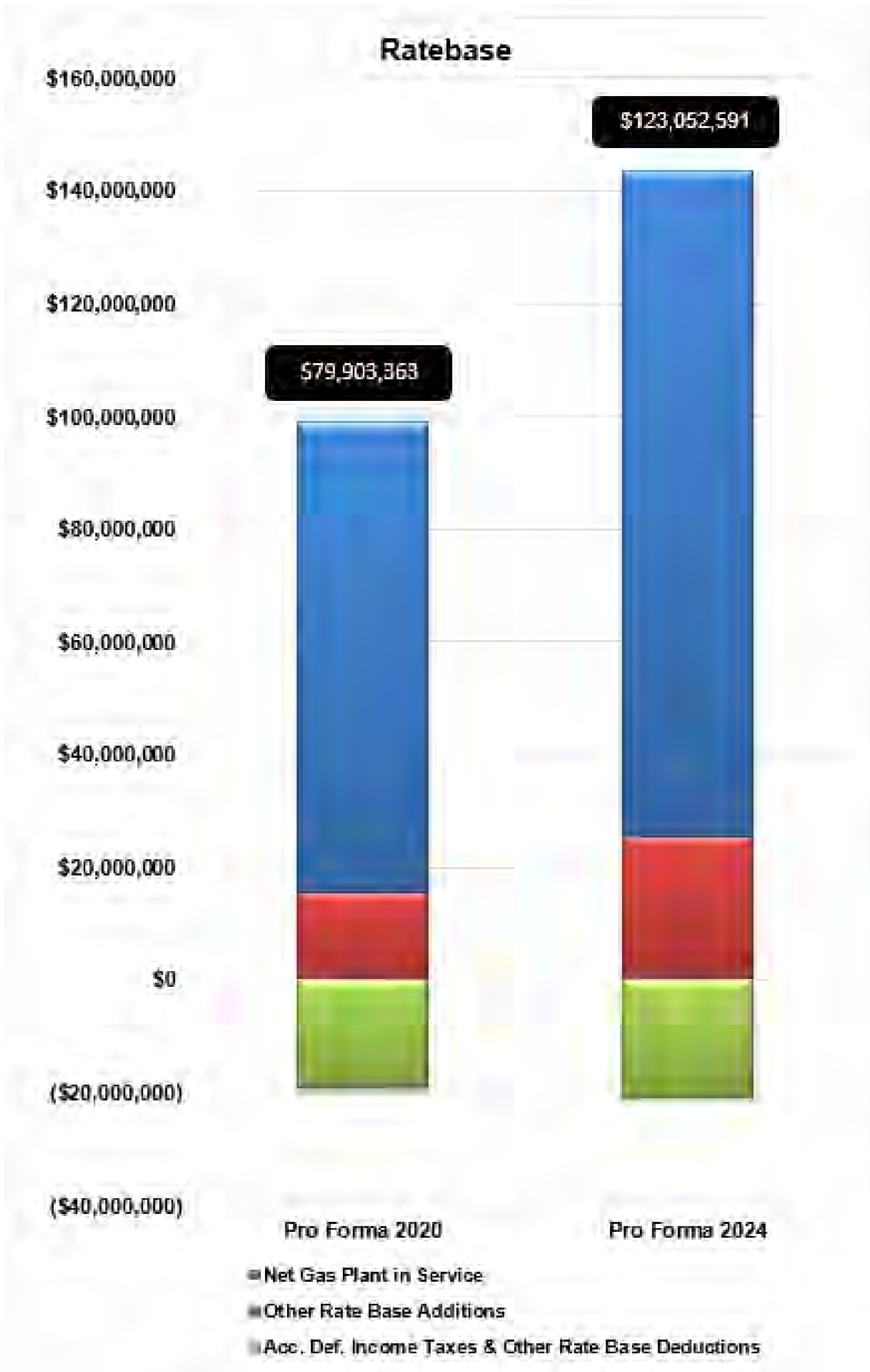
A. As shown in the table below, the $9.4 million increase in revenue is driven primarily by:

	Amount (in millions)
O&M Expenses	$3.6
Rate Base	2.2
SSIP	1.7
Depreciation	1.4
Other	0.5
Net Increase	$9.4

Montana-Dakota's cost of doing business in Montana is increasing despite the Company's effort to control costs and increase efficiency. The Company is experiencing a $3.6 million increase in O&M expenses due to increased labor, vehicles and work equipment, and software maintenance costs. Rate base investment since the last case, including the significant investments in the System Safety Integrity Program (SSIP) referenced in the testimony of Mr. Jesse Volk, represents $3.9 million of the increase. Finally, increases in depreciation expense, primarily driven by the investment in rate base (and somewhat offset by the implementation of the updated depreciation studies), results in a revenue requirement increase of approximately $1.4 million.

Q. How has the Company's investments driven the need for an increase at this time?

A. As depicted in the graph below, the Company's net adjusted rate base has grown approximately $43 million or 54 percent since the Pro Forma 2020 rate base.


Ratebase
$160,000,000
$140,000,000
$120,000,000
$100,000,000
$80,000,000
$60,000,000
$40,000,000
$20,000,000
$0
($20,000,000)
($40,000,000)
$79,903,363
$123,052,591
Pro Forma 2020
Pro Forma 2024
Net Gas Plant in Service
Other Rate Base Additions
Acc. Def. Income Taxes & Other Rate Base Deductions

As shown in the table below, the Company's total O&M costs have increased over those in the Company's last gas rate case. After adjusting the 2020 Pro Forma O&M to exclude the cost of gas, the Company's Pro Forma O&M expenses are projected to increase approximately 17.5 percent, which is well below the 22 percent increase in the price of goods and services from January 2020 to May 2024 as calculated by the U.S. Bureau of Labor Statistics. This represents a 4.11 percent compounded increase per year since the last filing.

	Pro Forma 2020	Pro Forma 2024	Variance	Percent Variance
Cost of Gas	$37,322,531	$49,978,363	$12,655,832	33.91%
Labor	8,107,980	9,096,763	988,783	12.20%
Benefits	1,911,960	1,863,960	(48,000)	-2.51%
Vehicles and Work Equipment	537,354	1,147,576	610,222	113.56%
Software Maintenance	515,568	844,871	329,303	63.87%
Insurance	477,896	666,268	188,372	39.42%
Rent	377,095	505,309	128,214	34.00%
Regulatory Commission	141,450	305,033	163,583	115.65%
Other O&M	3,341,030	3,671,541	330,511	9.89%
Total O&M Expense	$52,732,864	$68,079,684	$15,346,820	29.10%
Total Excluding Cost of Gas	$15,410,333	$18,101,321	$2,690,988	17.46%

Q. How have the Company's labor expenses changed since the last case?

A. Montana-Dakota's projected labor expenses for the year ending December 2024 have increased approximately 12 percent since the 2020 rate case which represents a 2.92 percent compounded year over year increase.

Additionally, Montana-Dakota, like many other organizations in the country, is experiencing additional turnover pressures within its labor force, particularly with respect to an increasing percentage of the workforce being of traditional retirement age. These additional pressures, when combined with the current competitive job market, have resulted in increased labor market costs, particularly for those in entry level, trade, and positions requiring specialized skills.

On March 18, 2024, Montana-Dakota finalized its labor contract with the System Council U-13 of the IBEW. This contract, which runs through April 2026, defined an approximate 6.00 percent labor expense increase per year, and its effect is discussed in the testimony of Ms. Tara R. Vesey.

Q. Have there been other increases in expenses since the last case?

A. Montana-Dakota has seen other increases to O&M expenses since the last case, such as vehicles and work equipment and software maintenance. The operation and maintenance expenses associated with Vehicles and Work equipment increased approximately $611,000 primarily due to increased depreciation rates for Power Operated Equipment within the study supported by Mr. Larry E. Kennedy. Software maintenance expense increased approximately $329,000 from the 2020 rate case due to increases in license renewals and mandated security needs.

Q. Have you performed a depreciation study for inclusion in this request?

A. Yes. Depreciation studies for Montana-Dakota's gas and common plant in service were performed by Mr. Kennedy of Concentric Advisors, ULC. Mr. Kennedy has provided testimony on behalf of the Company and is recommending a composite gas plant depreciation rate of 3.77 percent and a 5.31 percent common depreciation rate, both of which are based on plant in service as of December 31, 2021. The impact of the depreciation study results in a Montana gas jurisdiction decrease of approximately $252,000 in the revenue requirement, as compared to the previously approved rates. However, despite the lower overall composite depreciation rates from the currently approved rates, the Company's overall depreciation expense is $1.4 million higher than the previously approved rates due to the approximately 54 percent increase in gross plant investment since the last case.

Q. Has the Company added any other new adjustments to be considered?

A. Included in the Settlement for Docket No. 2020.06.076, Montana-Dakota agreed to perform a Lead/Lag study and include the corresponding Cash Working Capital adjustment in its next gas rate case. Therefore, Montana-Dakota has included a Cash Working Capital adjustment that increases the rate base by approximately $1.1 million.

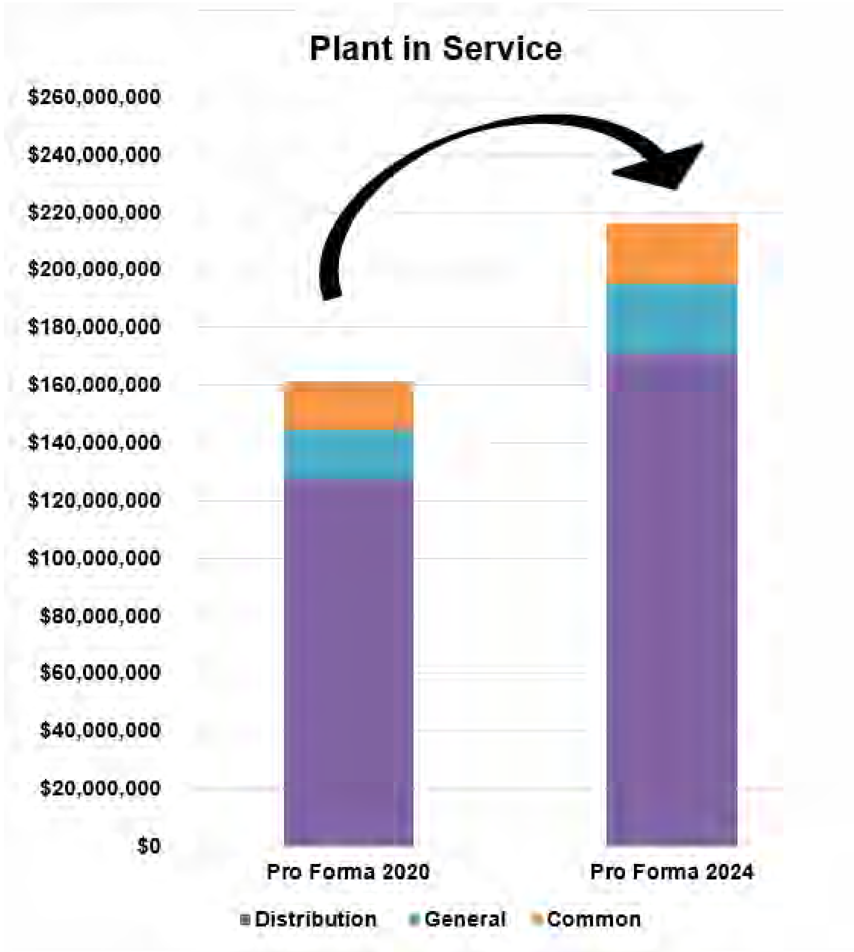
This adjustment will be more fully explained by Mr. Michael Adams and Ms. Vesey.

Q. What incremental investments are included in this case as pro forma December 2024?

A. The Company has included incremental investments for 2024 of approximately $19.3 million and are associated with the following investments:

- Distribution plant investment of approximately $13.6 million, including distribution mains and service line replacements and upgrades required to maintain safe and reliable service, as discussed in greater detail by Mr. Martuscelli and Mr. Volk;
- General plant additions of approximately $3.1 million, primarily associated with work equipment, structures and improvements, and town border stations, as discussed in greater detail by Mr. Nieuwsma.
- Common plant additions of approximately $2.6 million, primarily associated with work equipment, structures and improvements, and Work Asset Management software, as discussed in greater detail by Mr. Gilchrist.

The table below shows the investment in plant assigned and allocated to Montana gas operations from 2020 to pro forma 2024.



Q. Would you please describe the current investment in distribution facilities to improve system safety and reliability?

A. Montana Dakota has a SSIP that accounts for a substantial portion of the Company's natural gas distribution investment. These replacements address the high risk systems based on results of Montana-Dakota's integrity management program that is covered in more detail by Mr. Jesse Volk.

Furthermore, due to reliability concerns, Montana-Dakota has identified the need to upgrade Town Border Stations (TBS) in Park City and Sidney. These upgrades are necessary and are further explained by Mr. Shawn Nieuwsma.

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

A. The allocation of revenue is based on the Class Cost of Service Study, which is supported by Mr. Ronald J. Amen. The proposed percentage change in

rates by customer class are as follows:

Rate Class	Overall Class Impact
Residential Service	16.4%
Firm General Service	3.8%
Small Interruptible Service	0.3%
Large Interruptible Service	2.5%
Total	11.1%

Q. What return is Montana-Dakota requesting in this case?

A. Montana-Dakota is requesting an overall return of 7.756 percent, inclusive of a return on equity (ROE) of 10.8 percent. Ms. Ann E. Bulkley's analysis indicates that a 10.8 percent ROE is fully justified and supported based on the results of her studies.

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

A. Yes. Interim rate relief is being sought in this case consistent with the Administrative Rules of Montana (ARM) § 38.5.5 Interim Utility Rate

Increases. Montana-Dakota's overall rate of return on its investment was 2.600 percent as of December 31, 2023, resulting in a return on equity of 0.608 percent, well below the authorized return of 7.208 percent. The amount of interim relief sought is $7,984,385 or 10.2 percent and consists of the Company's pro forma 2024 revenue requirement adjusted to reflect the return on equity of 9.4 percent authorized in Docket No. D2017.9.079 (the most recently stated ROE) and the exclusion of items that were not a part of the last rate case. 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. Please identify the witnesses who will testify on behalf of Montana-Dakota in this proceeding.

A. Following is a list of witnesses who will provide testimony and/or exhibits in support of the Company's application:

- Ms. Tammy J. Nygard, Controller for Montana-Dakota, will testify regarding the overall cost of capital, capital structure, and overall debt costs.
- Ms. Ann E. Bulkley, Principal for The Brattle Group, will testify regarding the appropriate cost of common equity and the reasonableness of the capital structure for Montana-Dakota's Montana gas operations.

- Mr. Jesse Volk, System Integrity Manager for Montana-Dakota will testify regarding the Company's System Safety and Integrity Program (SSIP) and the Company's SSIP projects capital expenditures.
- Mr. Shawn Nieuwsma, Director of Gas Supply for Montana-Dakota, will testify regarding the Company's Park City and Sidney, Montana town board stations capital expenditures.
- Mr. Hart Gilchrist, Vice President of Safety, Process Improvement, and Operations Systems for Montana-Dakota will testify regarding the Company's Work and Asset Management system deployment.
- Mr. Eric P. Martuscelli, Vice President of Field Operations for Montana-Dakota, will testify regarding the Company's mains and service lines replacement capital expenditures, and Billings Reinforcement capital expenditures.
- Mr. Larry E. Kennedy, Senior Vice President for Concentric Advisors, ULC., will testify regarding the depreciation studies for Montana-Dakota's gas and common operations of the plant in service as of December 31, 2021, that supports the proposed depreciation rates in this filing.
- Mr. Michael J. Adams, Senior Vice President for Concentric Energy Advisors, Inc., will testify regarding Montana-Dakota's lead lag study and cash working capital adjustment.
- Mr. Nathan A. Bensen, Regulatory Analyst for Montana-Dakota will testify regarding the pro forma volumes in this case.

- Ms. Tara R. Vesey, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the total revenue requirement, provide an overview of the interim revenue requirement necessary for Montana gas operations, and present proposed Rate 88 tariff changes.
- Mr. Ron J. Amen, Managing Partner for Atrium Economics, LLC, will testify regarding Montana-Dakota'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.

Q. Ms. Kivisto, are the rates requested in this proceeding just and reasonable?

A. In my opinion, the proposed rates are just and reasonable as they are reflective of the total costs being incurred by Montana-Dakota to provide safe and reliable natural gas service to its customers. The proposed rates will provide Montana-Dakota an opportunity to earn a fair and reasonable return on its Montana gas operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ *Nicole A. Kivisto*

Nicole A. Kivisto
President and Chief Executive Officer

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2024.05.061

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. (MDU Resources) as well as Great Plains Natural Gas Co. (Great Plains), a division of Montana-Dakota, collectively the MDU Utilities Group.

Q. Would you 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 the MDU Utilities Group.

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 22 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 A, Statement B, and Statement F.

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

A. Yes, they were.

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

A. Yes, they are.

Q. Would you describe Statement A and Statement B?

A. Statement A, pages 1 and 2 show Montana-Dakota's balance sheet as of December 31, 2022 and December 31, 2023 with March 31, 2023 and March 31, 2024 information shown on pages 3 and 4, with notes to the financial statements following. Statement B consists of Montana-Dakota's income statement for the twelve months ended December 31, 2023 and the three months ended March 31, 2024. These statements have been prepared from the Company's books and records that are maintained in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. Would you please explain Statement F?

A. Statement F shows the average utility capital structure of Montana-Dakota for the twelve months ended December 31, 2023, and the pro forma capital structure for 2024. Statement F 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 7.756 percent. The basis for the requested 10.80 percent return on equity contained within the overall requested rate of return is supported by the testimony of Ms. Ann E. Bulkley.

Statement F, Rule 38.5.146 summarizes the average of the actual utility capital structure on December 31, 2023 and the pro forma average and year end capital structure and the related utility costs of capital for 2024. As shown on page 1, the components of the 2024 pro forma annual rate of return, which are used by Ms. Tara R. Vesey to calculate the revenue requirement, are:

	Ratio	Cost	Weighted Cost
Long Term Debt	44.586%	4.576%	2.040%
Short Term Debt	5.257%	5.681%	0.299%
Common Equity	50.157%	10.800%	5.417%
Rate of Return	100.000%		7.756%

Page 2 of Rule 38.5.146 reflects the Company's average utility common equity balance on December 31, 2023 and the pro forma balance on December 31, 2024. The changes to the common equity balances include the normal changes, including pro forma earnings.

Q. How does the Company finance its gas utility operations and determine the amount of 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 is making significant capital expenditures for new plant investment throughout its service territory, especially in mains and services, including System Safety and Integrity Projects (SSIP) and town border stations. 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 structure at year end. 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 did not issue any new long-term debt in 2023. In July 2024, the Company had $60 million of senior notes mature and has issued long-term debt of $125 million, partially to replace the $60 million senior notes.

Q. What does Statement F, Rule 38.5.147 show?

A. Page 1 is a summary showing the Company's long-term debt on December 31, 2023 and associated cost of debt, and it shows the pro forma long-term debt and associated costs for 2024, as well as the average cost of debt for the two periods. Page 2 shows the cost and the debt balance by issue on December 31, 2023. Page 3 shows the pro forma cost and the debt balance by issue on December 31, 2024, including the additional $125 million of long-term debt previously discussed.

Q. How did you derive the pro forma cost of debt for 2024?

A. The pro forma cost of debt for 2024 is based upon the yield to maturity of each debt issue outstanding.

Q. Would you please describe Statement F, Rule 38.5.147, page 4 and explain the amortization method utilized?

A. Page 4 reflects the annual amortization of the costs associated with the redemption of long-term debt. The balance was fully amortized in 2022 and therefore, there are no costs associated with these notes in 2023 or 2024.

Q. Would you please describe Statement F, Rule 38.5.147, page 5?

A. Page 5 presents the average short-term debt balance for 2023, the pro forma average short-term debt balance for 2024, and 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. Please describe the remaining portion of Statement F.

A. Statement F includes Rule 38.5.148, 149-151, and 152. Montana Dakota has reacquired all preferred stock, no longer has publicly traded common stock, and does not have first mortgage bonds outstanding. Therefore, each of the above noted Rules was addressed indicating such.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

Tammy Nygaard

Controller, Utility Group

MONTANA-DAKOTA UTILITIES CO.
BEFORE THE MONTANA PUBLIC SERVICE COMMISSION
DOCKET NO. 2024.05.061
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 One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues.

Q2. On whose behalf are you submitting this testimony?

A2. I am submitting this direct testimony before the Montana Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. My testimony addresses the regulated natural gas utility operations of Montana-Dakota Utilities Co. within Montana ("Montana-Dakota" or the "Company").

Q3. Please describe your background and professional experience in the energy and utility industries.

A3. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, and have more than 25 years of experience consulting to the energy industry. I have provided testimony regarding financial matters, including the cost of capital, before numerous regulatory agencies. I have advised 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. A summary of my professional and educational background is presented in Exhibit No.___ (AEB-2), Schedule 1.

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q4. What is the purpose of your direct testimony?

A4. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the Montana-Dakota's return on equity ("ROE") for its natural gas utility operations 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 15, which were prepared by me or under my direction.

Q5. Please provide a brief overview of the analyses that support your ROE recommendation.

A5. I have estimated the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration the business and regulatory risk of the Company relative to the proxy group, and the Company's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I do consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q6. How is the remainder of your direct testimony organized?

A6. The remainder of my direct testimony is organized as follows:

- 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 the Company's cost of equity.
- Section V explains my selection of the proxy group.
- Section VI describes my cost of equity analyses and the basis for my recommended ROE in this proceeding.
- 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 provides an assessment of the reasonableness of the Company's proposed capital structure.
- Section IX presents my conclusions and recommendations.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q7. Please summarize the key factors that you consider your analyses and upon which you base your recommended ROE.

A7. My analyses and recommendations consider the following:

- The United States ("U.S.") Supreme Court's *Hope* and *Bluefield* decisions established the standards for determining a fair and reasonable authorized ROE for public utilities, 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.[1]
- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.

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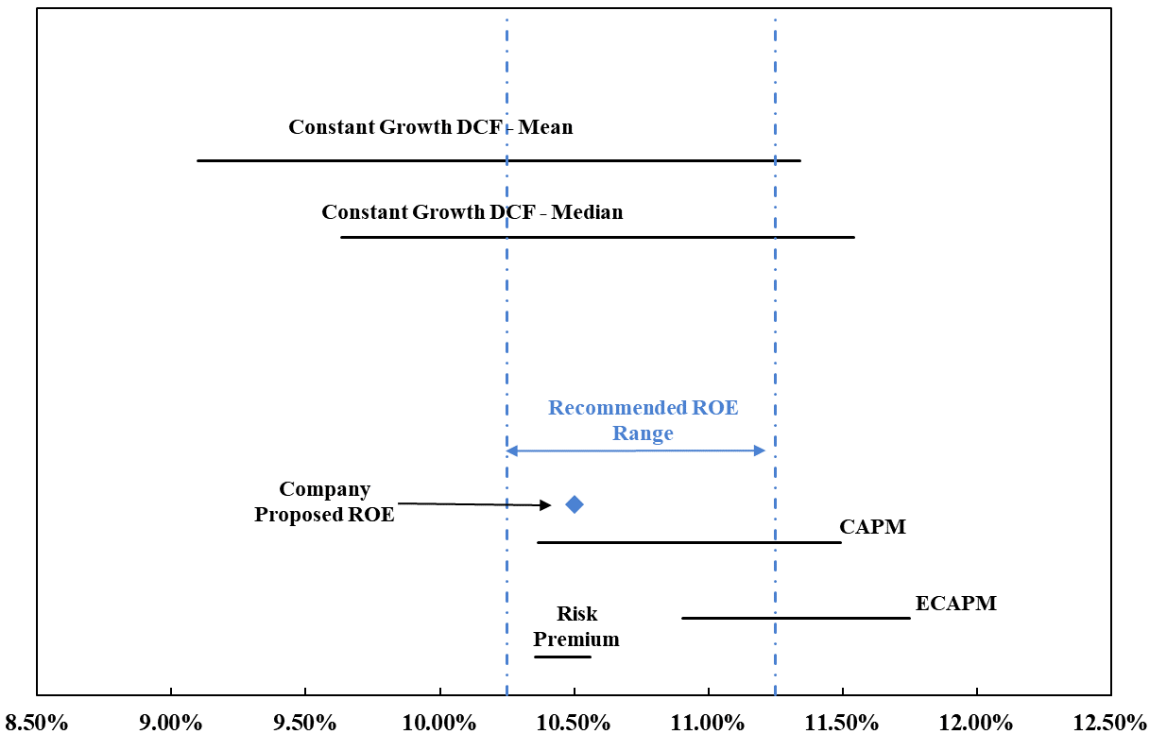
1 Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield").

- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)
- Although the companies in my proxy group are generally comparable to Montana-Dakota, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I consider the Company's regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q8. What are the results of the models that you have used to estimate the market-based cost of equity for Montana-Dakota?

A8. Figure 1 summarizes the range of results produced by the cost of equity analyses.

Figure 1: Summary of Cost of Equity Analytical Results



As shown, the range of results across all methodologies 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 varies considerably across methodologies.

Q9. Are prospective capital market conditions expected to affect the results of the cost of equity analyses for the Company during the period in which the rates established in this proceeding will be in effect?

A9. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Long-term interest rates have increased substantially over the past two years and are expected to remain relatively high at least over the next year in response to inflation.
- Since (i) utility dividend yields are less attractive than the risk-free rates of government bonds; (ii) interest rates are expected to remain near current levels over the next year, and (iii) utility stock prices are inversely related to changes in interest rates; utility share prices could either decline or remain depressed.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of elevated interest rates and expect the sector to underperform in 2024.
- Consequently, it is important to consider that if utility share prices decline, the results of the DCF model, which relies on current utility share prices, would understate the cost of equity during the period that the Company's rates will be in effect.
- Rating agencies have responded to the risks of the utility sector, citing factors including elevated capital expenditures, interest rates, and inflation that create pressures for customer affordability and prompt rate recovery, and have noted the importance of regulatory support in their current outlooks.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the reasonableness of the Company's proposed ROE.

Q10. What is your recommended ROE for the Company in this proceeding?

A10. Considering the analytical results of the market-based cost of equity models, current and prospective capital market conditions and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.25 percent to 11.25 percent is reasonable, and within that range, I recommend and ROE of 10.80 percent.

Q11. Is the Company's requested capital structure reasonable?

A11. The Company's proposed equity ratio of 50.157 percent is well within the range of the actual capital structures of the utility operating subsidiaries of the proxy group companies and is below the average of the proxy group. Further, the Company's proposed equity ratio is reasonable considering that credit rating agencies have identified in their outlook for the utility sector significant risks such as elevated interest rates and inflation, record levels of capital spending, and the need to fund capital spending in a credit supportive manner.

III. REGULATORY GUIDELINES

Q12. Please describe the principles that guide the establishment of the cost of capital for a regulated utility.

A12. The U.S. 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.[2]

Q13. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A13. Yes. In Docket No. 2022.07.078 for NorthWestern Energy ("NorthWestern"), the Commission stated that:

> The Commission evaluates the ROE used to set utility rates according to well-established regulatory case law generally referred to as the fair return standard. There are three prongs to the standard: (1) a utility's ROE should be commensurate with those of businesses with similar risk; (2) the ROE should be sufficient to maintain the financial integrity of the utility; and (3) the ROE should be adequate to enable the utility to attract investors and capital on reasonable terms. *Fed. Power Comm'n. v. Hope Nat. Gas Co*., 320 U.S. 591, 603 (1944); *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692–93 (1923).[3]

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I have employed to estimate the cost of equity and recommend and ROE for the Company, including the principle that an allowed rate of return must be sufficient to enable regulated companies like Montana-Dakota to attract capital on reasonable terms.

Q14. Why is it important for a utility to have a reasonable opportunity to earn a return that is adequate to attract capital at reasonable terms?

A14. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable gas service while maintaining its financial integrity. The

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[2] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

[3] Docket No. 2022.07.078, Order No. 7860y, In re NorthWestern Energy's Application for Authority to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design (October 27, 2023), at 17.

authorized return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost, which negatively affects customers.

Q15. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A15. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities nationally. Therefore, the ROE authorized for 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 within that jurisdiction generally, and for that utility particularly. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

While Montana-Dakota is committed to investing the required capital to provide safe and reliable service, because Montana-Dakota is a wholly-owned subsidiary of MDU Resources Group, Inc. ("MDU"), the Company competes with the other MDU subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for MDU to consider the authorized ROE of each of its subsidiaries.

Q16. What is the standard for setting the ROE in any jurisdiction?

A16. The stand-alone ratemaking principle is a foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. Consistent with this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for Montana-Dakota's gas operations in Montana.

Q17. Does the fact that the Company is a subsidiary of MDU, a publicly-traded company, affect your analysis?

A17. No. In this proceeding, consistent with the stand-alone ratemaking principle, it is appropriate to establish the cost of equity for the Company, not its publicly-traded entity, MDU. More importantly, however, it is appropriate to establish a cost of equity and capital structure that provide the Company the ability to attract capital on reasonable terms on a stand-alone basis and within MDU.

Q18. Are the regulatory framework, the authorized ROE, and equity ratio important to the financial community?

A18. Yes. The regulatory framework is one of the most important factors in investors' assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for supporting a utility's creditworthiness and financial stability in the jurisdiction. To the extent that authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, such actions are considered by both debt and equity investors in the overall risk assessment of the regulatory jurisdiction in which the company operates.

Q19. What are your conclusions regarding regulatory guidelines?

A19. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn an ROE that is adequate to attract capital at reasonable terms and sufficient to ensure its financial integrity. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. 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. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q20. Why is it important to analyze capital market conditions?

A20. The models used to estimate the cost of equity rely on market data and thus the results of those models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, including stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE, and the ROE to be used for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is important to consider projected market data to estimate the return for that forward-looking period.

Q21. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A21. The cost of equity for regulated utility companies is affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) relatively high inflation; and (3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

A. Inflationary Expectations in Current and Project Capital Market Conditions

Q22. What has the level of inflation been over the past few years?

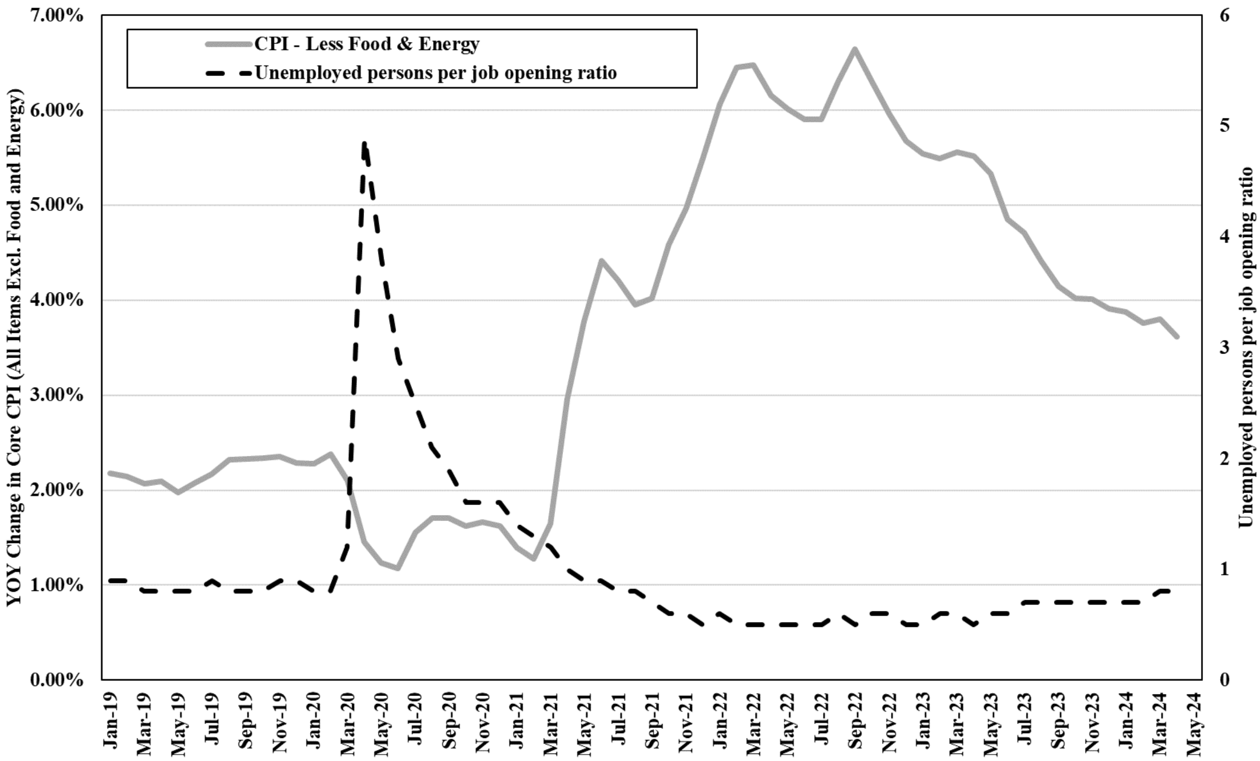
A22. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982.[4] Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain significantly above the Federal Reserve's target level of 2.0 percent.

In addition, I also considered the ratio of unemployed persons per job opening, which is currently 0.8 and has been consistently below 1.0 since 2021, despite the Federal Reserve's accelerated policy normalization. This metric indicates sustained strength in the labor market. Further, the May 2024 jobs report showed that the U.S economy added 272,000 jobs in that month, which was significantly higher than the expectation, although the unemployment rate increased 0.1 percent to 4.0 percent.[5] Given the Federal Reserve's dual mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

4 Figure 2 presents the year-over-year ("YOY") change in core inflation, as measured by the Consumer Price Index ("CPI") excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

5 Jeff Cox, "U.S. adds a much-better-than-expected 272,000 jobs in May, but employment rate edges up to 4%," CNBC, June 7, 2024.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to May 2024[6]



Q23. What are the expectations for inflation over the near-term?

A23. Over the last several months the Federal Reserve Open Market Committee ("FOMC") has been clear that they intend to rely on market data before making any changes to interest rates. In the FOMC's meeting on June 12, 2024, Chairman Powell observed that the FOMC will make their decision "meeting by meeting."[7] Further, while the FOMC forecast one 25 basis point rate cut in 2024,[8] Chairman Powell noted that is just a projection and

6 Bureau of Labor Statistics.

7 Federal Reserve, Transcript of Chair Powell's Press Conference, June 12, 2024, at 4.

8 Federal Reserve, Summary of Economic Projections, June 12, 2024, at 2.

not a "plan," and indicated that the FOMC is prepared to maintain the current federal funds rate range higher for longer if needed to reduce inflation.[9]

Similarly, Boston Federal Reserve President Susan Collins recently commented that she thought the federal funds rate would need to be kept at its current level until there was greater confidence that inflation was moving sustainably towards 2 percent.[10] Ms. Collins cited improvements in supply chains as the reason inflation declined in 2023, but that may not continue in 2024 and that slower economic growth will be needed to reduce demand in order to further reduce inflation.[11] New York Federal Reserve President John Williams and Minneapolis Federal Reserve President Neel Kashkari also stated that the federal funds rate will need to remain at its current level for longer as more data is collected.[12] Mr. Kashkari recently added that he wanted to see "[m]any more months of positive inflation data" before there is rate cut and that he has not ruled out further rate increases if inflation does not continue to decrease.[13]

Q24. What is the market's expectation about interest rate cuts?

A24. The market has recognized the strength in the economy and the labor market and has tempered its expectations that regarding how much the FOMC will decrease the federal funds rate in 2024. The CME Group, which publishes a "FedWatch" probability chart of FOMC activity, reported as of June 14, 2024 that the federal funds rate futures contracts

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9 Federal Reserve, Transcript of Chair Powell's Press Conference, June 12, 2024, at 4.

10 Steve Matthews, "Fed's Collins Says Reaching 2% Inflation Goal May Take Longer." Bloomberg, May 8, 2024.

11 Jennifer Schonberger, "Collins Becomes Latest Fed Official to Warn Rates Will Likely Stay Higher for Longer," Yahoo! Finance, May 8, 2024.

12 *Id*.

13 Karen Gilchrist, "Fed's Kashkari wants to see 'many more months' of positive inflation data before a rate cut," CNBC, May 28, 2024.

reflect an expectation of approximately 50 basis points in rate cuts this year, which is substantially lower than the 150 basis points in rate cuts that were expected in January 2024.[14] In summary, the market is expecting that interest rates will remain higher for longer than anticipated in at the beginning of 2024.

B. The Federal Reserve to Continue Use of Monetary Policy to Address Inflation

Q25. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A25. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Since the March 2022 FOMC meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.25 percent to a range of 5.25 percent to 5.50 percent. While inflation has declined from its peak, it still is above the Federal Reserve's target of 2.0 percent, and therefore, as just noted, the Federal Reserve anticipates maintaining short-term interest rates higher for longer in order to achieve its goal of 2.0 percent inflation over the long-run.

[14] CME Group, FedWatch Tool, accessed on June 14, 2024.

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q26. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A26. Yes. As the Federal Reserve has substantially increased the federal funds rate in response to increased levels of inflation that have persisted for longer than originally projected, longer term interest rates have also increased. As shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has approximately tripled, increasing from 1.47 percent on December 15, 2021 to 4.51 percent at the end of May 2024.

Figure 3: 10-Year Treasury Bond Yield, Janaury 2021 through May 30, 2024[15]

Q27. How have interest rates and inflation changed since the Company's last rate case?

A27. As shown in Figure 4, short-term and long-term interest rates and inflation have increased substantially since the Commission adopted the settlement in the Company's last rate proceeding. For example, long-term interest rates have increased by more than 275 basis points.

[15] S&P Capital IQ Pro.

Figure 4: Change in Market Conditions Since Company's Last Rate Case

Docket	Date	Federal Funds Rate	30-Day Avg 30 Year Treasury Bond Yield	Core Inflation Rate
2020.06.076	2/16/2021	0.08%	1.89%	1.29%
Current Proceeding	5/31/2024	5.33%	4.66%	3.63%
	Increase / (Decrease):	*5.25%*	*2.77%*	*2.34%*

Q28. What have equity analysts said about long-term government bond yields?

A28. Equity analysts have noted that they expect the yields on long-term government bonds to remain elevated. For example, the consensus estimate of the average yields on the 30-year Treasury bond reported by *Blue Chip Financial Forecasts* is 4.40 percent through 3Q/2025 and is also 4.30 percent over the longer term (through 2030), meaning long-term interest rates are expected to remain elevated during the period that the Company's rates will be in effect.[16] Therefore, investors expect interest rates to remain elevated for at least the next 15 months. As a result, it is reasonable to expect that if government bond yields remain elevated, the cost of equity will remain higher than at the time of the Company's last rate proceeding.

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q29. Are utility share prices correlated to changes in yields on long-term government bonds?

A29. Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa.

[16] *Blue Chip Financial Forecasts*, Vol. 43, No. 6, May 31, 2023, at 2.

For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (i.e., increases in bond yields resulted in the decline of utility share prices).[17]

Q30. What are equity analysts' current projections regarding the performance of the utilities sector over the near-term?

A30. Various equity analysts continue to project that utilities will underperform the broader market given the substantial increases in interest rates over the past two years:

- Fidelity Investments classifies the utility sector as underweight.[18]
- CFRA Research recently classified the utility sector as underweight, stating that the 10-year Treasury yield, which CFRA noted is the "benchmark for gauging the attractiveness of utility valuations and yields," exceeded the dividend yield of the utilities included in the S&P Composite 1500.[19]
- UBS classified the 11 sectors of the S&P 500 for 2024 as either most preferred, neutral, or least preferred with the utility sector being classified as one of UBS's three least preferred sectors (*i.e.*, utilities, materials and real estate).[20]
- Professional investors surveyed by *Barron's* in its most recent Big Money poll published in May 2024 selected the utility sector as one of the five equity sectors that they liked the least over the next twelve months, indicating they are projecting that utilities will underperform the broader market over the next twelve months.[21]

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17 Justina Lee, "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks," Bloomberg.com, March 11, 2021.

18 Fidelity Investments, "Second Quarter 2024 Investment Research Update," April 22, 2024, p. 3.

19 Daniel Rich, "U.S. Utilities – Cherry-picking Quality in an Underperforming Sector," CFRA, January 26, 2024,

20 Jason Capul, "UBS Prefers Info Tech, Consumer Staples and Energy in 2024," Seeking Alpha, December 12, 2023.

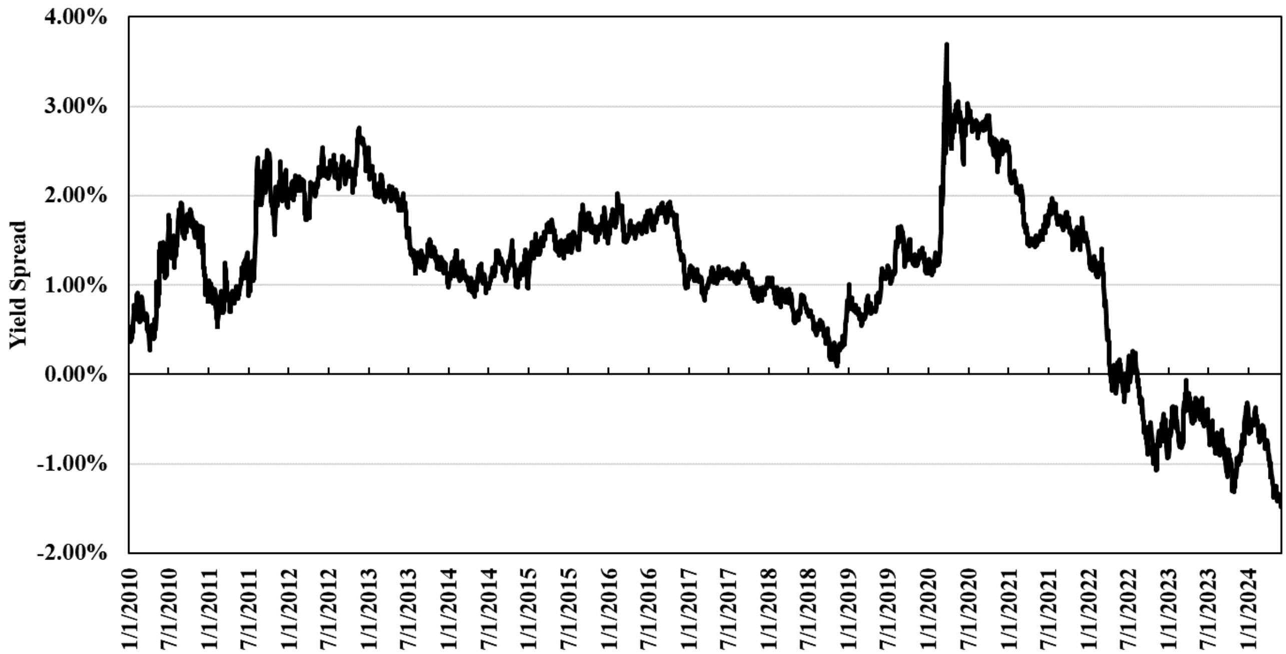
21 Paul La Monica, "The Stock Market Will Rise Nearly 10% More This Year, Money Managers Predict in Barron's Latest Poll," Barron's, May 3, 2024.

Q31. Do equity analysts expect the utility sector to underperform over the near-term?

A31. Yes. Equity analysts expect the utility sector to underperform given that, on average, the yields for the utility sector remain lower than the yields on long-term government bonds. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through May 2024 (*i.e.*, yield spread). I selected the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds.

As shown in Figure 5, the recent significant increase in long-term government bonds yields has resulted in the yield on long-term government bonds exceeding the dividend yields of utilities. The yield spread as of May 31, 2024 was negative 1.47 percent, meaning that the yield on the 10-year Treasury bond exceeds the dividend yield for the S&P Utilities Index. However, the long-term average yield spread from 2010 to present is 1.16 percent. Therefore, the current yield spread is well below the long-term average. Because of the fact that the yield spread is currently well below the long-term average, and the expectation that interest rates will remain relatively high through at least the next year, it is reasonable to conclude that the utility sector will most likely underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated, thus resulting in a decrease in the share prices of utilities.

Figure 5: Yield Spread between the Dividend Yield on the S&P Utilities Index and the Yield on the 10-year Treasury Bond – January 2010 – May 2024[22]



E. Conclusion

Q32. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A32. Due to their effect on the estimated cost of equity, it is important that current and projected market conditions be considered in setting the forward-looking ROE in this proceeding. Long-term interest rates are substantially higher than when the decision was issued in the Company's last rate proceeding and are expected to remain higher for longer as macroeconomic indicators continue to indicate a strong economy and inflation remains persistently above the Federal Reserve's long-term target level. These factors demonstrate that the cost of equity has increased since the Company's last rate proceeding, which should be considered when establishing the ROE in this proceeding.

[22] S&P Capital IQ Pro and Bloomberg Professional.

V. PROXY GROUP SELECTION

Q33. Please provide a brief profile of Montana-Dakota.

A33. Montana-Dakota is a wholly owned subsidiary of MDU. The Company provides natural gas service to approximately 88,800 customers in 40 communities in Montana.[23] As of December 31, 2023, the Company's net utility natural gas plant in Montana was approximately $107.53 million.[24] In addition, the Company had total natural gas sales in Montana in 2023 of approximately 10.95 million dth.[25] Montana accounted for approximately 8 percent of MDU's total natural gas retail sales revenue in 2023.[26] Montana-Dakota currently has an investment-grade long-term rating of BBB (Outlook: Negative) from S&P and BBB+ (Outlook: Stable) from Fitch.[27]

Q34. Why have you used a group of proxy companies to estimate the cost of equity for Montana-Dakota?

A34. In this proceeding, the cost of equity is being estimated for a natural gas utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and the Company'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 the Company in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

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[23] Montana-Dakota Utilities Co. 2023 Annual Report to the Montana Public Service Commission, Schedule 29 at 34.

[24] Data provided by Company.

[25] Montana-Dakota Utilities Co. 2023 Annual Report to the Montana Public Service Commission, Schedule 35 at 42.

[26] MDU Resources Group, Inc., Form 2023 SEC Form 10-K at 15.

[27] S&P Global Ratings, November 8, 2023 and Fitch Ratings, August 3, 2023.

Even if the Company 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 estimate the appropriate cost of equity for the Company.

Q35. How did you select the companies included in your proxy group?

A35. I began with the group of 9 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 such companies 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.

Q36. What is the composition of your proxy group?

A36. The screening criteria discussed above is shown in Exhibit No.___(AEB-2), Schedule 3 and results in a proxy group consisting of the companies shown in Figure 6.

Figure 6: Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
NiSource	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

VI. COST OF EQUITY ESTIMATION

Q37. Please briefly discuss the ROE in the context of a regulated utility.

A37. The rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (*i.e.*, book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the rate of return. 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 observable market data when establishing the ROE.

Q38. How is the required cost of equity determined?

A38. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, 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 produced by multiple analytical techniques. 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 the subject company (in the context of the proxy group), in particular.

Q39. What methods did you use to estimate the cost of equity for the Company in this proceeding?

A39. I consider the results of the constant growth form of the DCF model, the CAPM, the ECAPM, and a BYRP analysis. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q40. Is it important to use more than one analytical approach?

A40. Yes. 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[28] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[29] recommend the CAPM, DCF, and BYRP approaches.

Further, the recent changes in market conditions discussed previously highlight the benefit of using multiple models since each model relies on different assumptions, certain of which

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[28] Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies* (3rd ed. 2000), at 214.

[29] Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice* (7th ed. 1994), at 341.

better reflect current and projected market conditions at different times. For example, the CAPM and ECAPM analyses rely directly on interest rates as an assumption in the models and therefore may more directly reflect the market conditions expected when the Company's rates are in effect. Accordingly, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

Q41. Has the Commission recognized that it is important to consider the results of multiple ROE estimation models?

A41. Yes. It is my understanding that in the Final Order for Docket No. 2022.07.078, the Commission determined a range of reasonable ROEs based on variations of both the DCF and the CAPM.[30]

A. Constant Growth DCF Model

Q42. Please describe the DCF approach.

A42. 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:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

[30] Docket No. 2022.07.078, Order No. 7860y, In re NorthWestern Energy's Application for Authority to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design, (October 27, 2023), at 19.

Where P_0 represents the current stock price, $D1 \ldots D\infty$ are all expected future dividends, and k is the discount rate, or required COE. 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.

Q43. What assumptions are required for the constant growth DCF model?

A43. The constant growth DCF model requires the following 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.

Q44. What market data did you use to calculate the dividend yield in your constant growth DCF model?

A44. The dividend yield in my constant growth DCF model is based on the proxy companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days as of May 31, 2024.

Q45. Why did you use three averaging periods for stock prices?

A45. 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 cost of equity 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.

Q46. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A46. Yes. 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.

Q47. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A47. In its constant growth form, the DCF model (*i.e.*, Equation [2]shown previously) assumes a single long-term growth rate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume that the dividend payout ratio remains constant and that earnings per share ("EPS"), dividends per share, and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. Therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS growth rates into the constant growth DCF model.

Q48. What sources of long-term growth rates did you rely on in your constant growth DCF model?

A48. My constant growth DCF model incorporates three sources of long-term projected EPS growth rates: (1) *Zacks Investment Research* (*Zacks*); (2) Yahoo! Finance; and (3) *Value Line*.

Q49. Why are EPS growth rates the appropriate growth rates to be relied on in the DCF model?

A49. Earnings are the fundamental driver of a company's ability to pay dividends; therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to reflect accurately investor perceptions of a company's growth prospects.

Q50. How do you calculate the range of results for the constant growth DCF models?

A50. I calculate the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, Yahoo! Finance, and *Value Line* projected EPS growth rates) for each of the proxy group companies. I use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculate results using the average EPS growth rate from all three sources for each proxy group company.

Q51. Please summarize the results of your constant growth DCF analyses.

A51. Exhibit No.___(AEB-2), Schedule 4 and Figure 7 summarize the results of the constant growth DCF models.

Figure 7: Summary of Constant Growth DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.00%	10.11%	11.24%
90-Day Avg. Stock Price	9.13%	10.24%	11.37%
180-Day Avg. Stock Price	9.17%	10.27%	11.41%
Average	9.10%	10.21%	11.34%
Median Results:			
30-Day Avg. Stock Price	9.52%	9.99%	11.43%
90-Day Avg. Stock Price	9.66%	10.07%	11.57%
180-Day Avg. Stock Price	9.72%	10.10%	11.62%
Average	9.63%	10.05%	11.54%

Q52. Have regulatory commissions acknowledged that the DCF model might understate the cost of equity given the current capital market conditions of relatively high inflation and elevated interest rates?

A52. Yes. For example, in its May 2022 decision establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission concluded that the current capital market conditions of high inflation and increased interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.
>
> …..
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[31]

Similarly, the Massachusetts Department of Public Utilities in a recent rate case for NSTAR Electric Company concluded that, given the increase in interest rates, there was

[31] *Penn. Pub. Util. Comm'n et.al. v, Aqua Penn. Wastewater Inc.*, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order at 154–155 (May 12, 2022).

"greater certainty" that the results of the DCF model were understating the cost of equity for the utility.[32]

B. CAPM Analysis

Q53. Please briefly describe the Capital Asset Pricing Model.

A53. 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 investors for the non-diversifiable or "systematic" risk of that security.[33] 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:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market ROE;

β = the 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.

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32 Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan, Docket D.P.U. 22-22, Final Order at 385-386 (Nov. 30, 2022).

33 Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

In this specification, the term ($r_m - r_f$) 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. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

$$\beta = \frac{Covariance\ (r_e, r_m)}{Variance\ (r_m)} \qquad [4]$$

Variance (r_m) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which 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.

Q54. What risk-free rate did you use in your CAPM analyses?

A54. I rely 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 4.66 percent;[34] (2) the average projected 30-year U.S. Treasury bond yield for the third quarter of 2024 through the third quarter of 2025, which is 4.40 percent;[35] and (3) the average projected 30-year U.S. Treasury bond yield for 2026 through 2030, which is 4.30 percent.[36]

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[34] S&P IQ Pro, as of May 31, 2024.

[35] *Blue Chip Financial Forecasts*, Vol. 43, No. 6, May 31, 2024, at 2.

[36] *Blue Chip Financial Forecasts*, Vol. 43, No. 6, May 31, 2024, at 14.

Q55. What beta coefficients did you use in your CAPM analysis?

A55. As shown in Exhibit No.___(AEB-2), Schedule 5, I use the beta coefficients for the proxy group companies as reported by *Bloomberg* and *Value Line*. The beta coefficients reported by *Bloomberg* are calculated using ten years of weekly returns relative to the S&P 500 Index. The beta coefficients reported by *Value Line* are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit No.___(AEB-2), Schedule 5, I also considered an additional CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group from 2013 through 2023, which are presented in Exhibit No.___(AEB-2), Schedule 6.

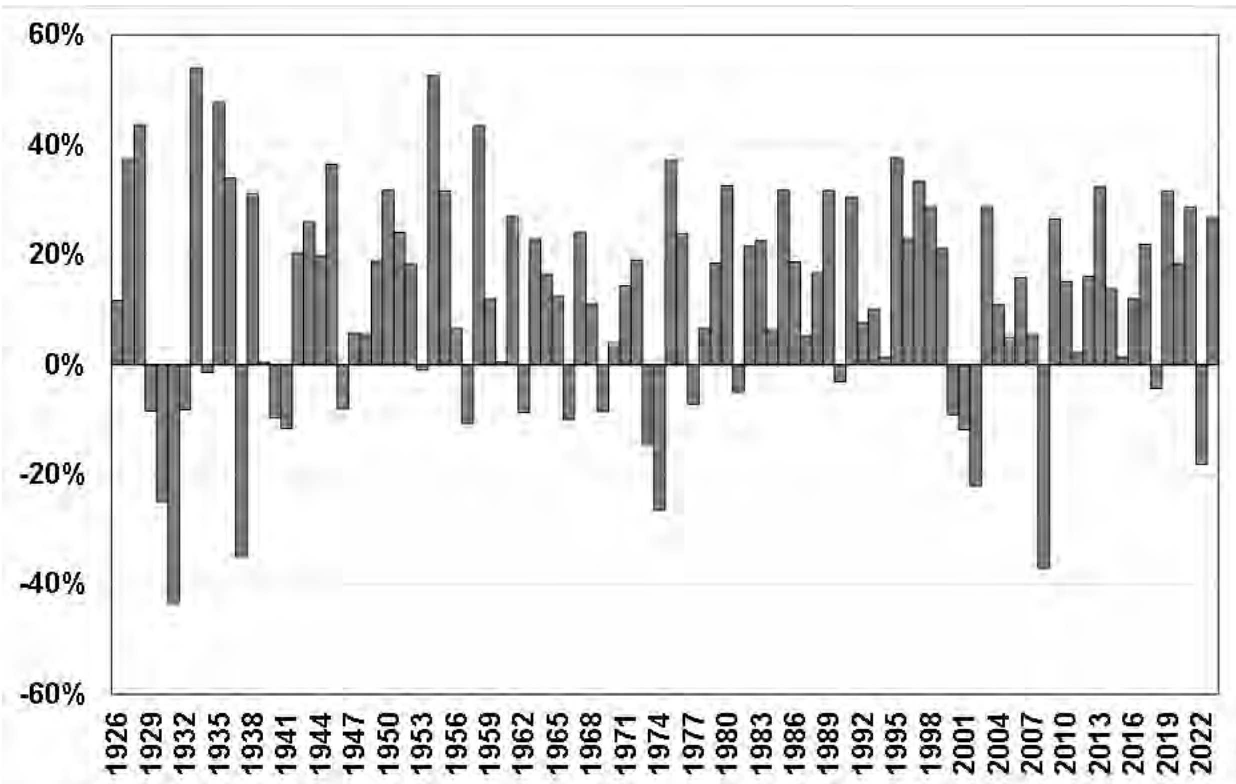
Q56. How do you estimate the market risk premium in the CAPM?

A56. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit No.___(AEB-2), Schedule 7, the expected market return is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.60 percent and a weighted long-term growth rate of 10.83 percent, the estimated required market return for the S&P 500 Index as of May 31, 2024 is 12.51 percent.

Q57. How does the expected market return compare to observed historical market returns?

A57. As show in Figure 8, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.51 percent is reasonable. In 50 out of the past 97 years (or approximately 52 percent of observations), the realized equity market return was at least 12.51 percent or greater.

Figure 8: Realized U.S. Equity Market Returns (1926–2022)[37]



Q58. Did you consider another form of the CAPM in your analysis?

A58. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for the Company.[38] The ECAPM calculates the 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

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[37] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook.

[38] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., June 1, 2006, at 189.

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.

The ECAPM 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 in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the CAPM underestimates the cost of equity for companies with a beta less than 1.0 and overestimates the cost of equity for companies with a beta greater than 1.0.[39]

Consistent with my 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 current *Bloomberg*, current *Value Line*, and long-term *Value Line* beta coefficients.

[39] *Id.,* at 191.

Q59. What are the results of your CAPM and ECAPM analyses?

A59. The results of my CAPM and ECAPM analyses are summarized in Figure 9, as well as presented in Exhibit No.___(AEB-2), Schedule 5.

Figure 9: CAPM and ECAPM Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.49%	11.46%	11.45%
Current Bloomberg Beta	10.61%	10.55%	10.53%
Long-term Avg. *Value Line* Beta	10.46%	10.39%	10.37%
ECAPM:			
Current *Value Line* Beta	11.75%	11.72%	11.71%
Current Bloomberg Beta	11.09%	11.04%	11.02%
Long-term Avg. *Value Line* Beta	10.97%	10.92%	10.90%

C. BYRP Analysis

Q60. Please describe your BYRP analysis.

A60. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for natural gas utilities as the historical measure of the cost of equity to determine the risk premium.

Q61. What is the fundamental relationship between the equity risk premium and interest rates?

A61. 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 (*i.e.*, as interest rates increase, the 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. The analysis presented in Exhibit No.___(AEB-2), Schedule 8 establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the long-term Treasury bond yield is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[40]

Q62. Is the BYRP analysis relevant to investors?

A62. Yes. Investors are aware of authorized ROEs 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. As discussed previously, utilities have experienced credit rating downgrades and been subject to a negative market reaction related to the financial effects of a rate case decision that included a below average authorized ROE. Because my BYRP analysis is based on authorized ROEs for utility companies relative to

[40] *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 (the author used a similar methodology, including using authorized 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 Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

Q63. What did your BYRP analysis reveal?

A63. As shown in Figure 10, from January 1980 through May 2024, 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:

$$RP = a + b(T)\mathrm{RP} = \mathrm{a} + \mathrm{b}(\mathrm{T}) \qquad [6]$$

Where

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

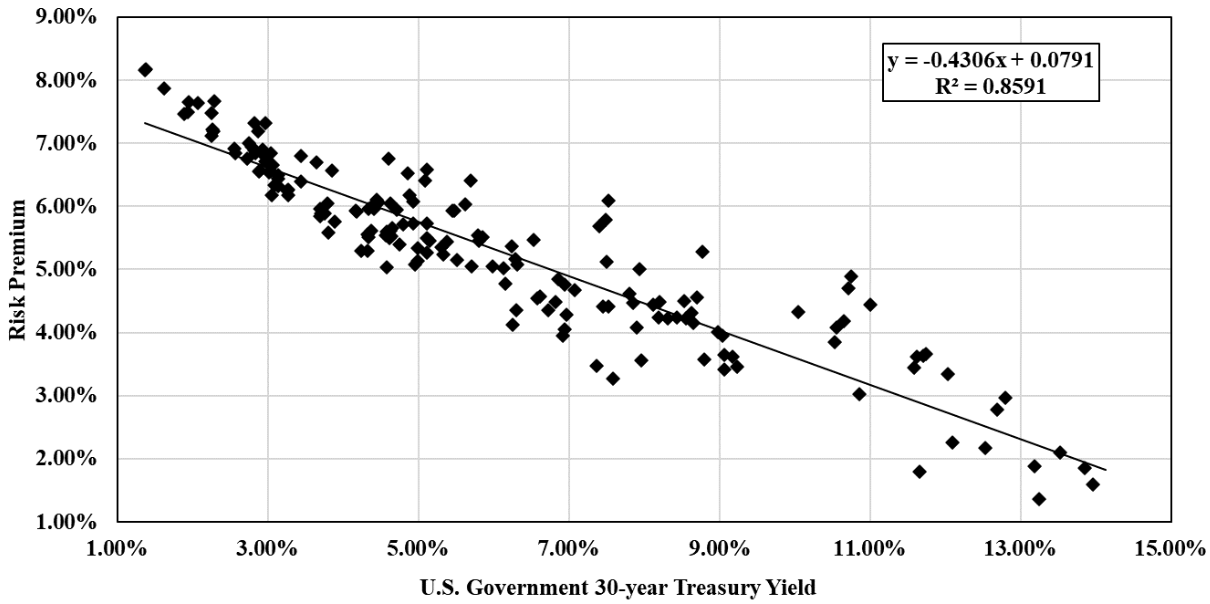
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs were derived from all of natural gas utility rate cases over this period as reported by RRA.[41] The equation's coefficients are statistically significant at the 99.00 percent level.

[41] The data was screened to eliminate limited issue rider cases, transmission cases, and cases that were silent with respect to the authorized ROE.

Figure 10: Risk Premium Regression Analysis



Q64. What are the results of your BYRP analysis?

A64. Figure 11 presents the results of my BYRP analysis, which is also presented in more detail in Exhibit No. ___(AEB-2), Schedule 8.

Figure 11: BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
Bond Yield Risk Premium	10.56%	10.41%	10.35%

Q65. How did the results of the BYRP inform your recommended ROE for Montana-Dakota?

A65. I have considered the results of the BYRP analysis in setting my recommended ROE for Montana-Dakota. As noted above, investors consider the ROE determination by a regulator when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The BYRP analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of natural gas utilities across the U.S.

VII. REGULATORY AND BUSINESS RISKS

Q66. Do the results of the cost of equity analyses alone provide an appropriate estimate of the cost of equity for the Company?

A66. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. Several additional factors must be considered when determining where the Company's cost of equity falls within the range of analytical results. These risk factors, discussed below, should be considered with respect to their overall effect on the Company's risk profile relative to the proxy group.

A. Small Size Risk

Q67. Is there a risk to a firm associated with small size?

A67. Yes. 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.[42]

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[42] Michael Annin, "Equity and the Small-Stock Effect," *Public Utilities Fortnightly*, October 15, 1995.

Q68. How does the smaller size of a utility affect its business risk?

A68. 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 reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q69. How does Montana-Dakota's natural gas operations in Montana compare in size to the companies in the proxy group companies?

A69. The Company's natural gas distribution operations are substantially smaller than the median for the proxy group companies in terms of market capitalization. While Montana-Dakota is not publicly-traded on a stand-alone basis, as shown on Exhibit No.___(AEB-2), Schedule 9, Montana-Dakota's common equity based on its proposed test year rate base and equity ratio is substantially smaller than the median market capitalization of the proxy group companies.

Q70. How did you estimate the size premium for Montana-Dakota?

A70. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for the Company using *Kroll* Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[43] As shown in Exhibit No.___(AEB-2), Schedule 9, the median market capitalization of the proxy group is approximately $3.59 billion, which corresponds to the fifth decile of *Kroll's* market capitalization data.[44] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.93 percent (*i.e.*, 93 basis points). In comparison, Montana-Dakota's common equity of approximately $61.72 million falls within the tenth decile, which corresponds to a size premium of 4.83 percent (*i.e.*, 483 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 390 basis points (*i.e.*, 4.83 percent minus 0.93 percent).

Q71. Have utility companies been included in the *Kroll* size premium study conducted?

A71. Yes. For example, as shown in Exhibit 7.2 of the *Kroll* (formerly *Duff & Phelps*) 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies contained in the fourth decile, which indicates that Kroll has included utility companies in its size risk premium study.[45]

Q72. Is the size premium applicable to companies in regulated industries such as natural gas utilities?

A72. Yes. For example, Zepp (2003) provided the results of two studies that showed evidence of the required risk premium for small water utilities. The first study, which was conducted by the Staff of the California Public Utilities Commission, computed proxies for beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that

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43 *Kroll*, Cost of Capital Navigator – Size Premium.

44 *Id*.

45 *Kroll*, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[46] The second study examined the differences in required returns over the period of 1987 through 1997 for two large and two small water utilities in California. As Zepp (2003) showed, the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities.[47]

Additionally, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry, and in particular subgroups of utilities.[48] The article considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM, which as previously discussed, I have also considered in estimating the cost of equity for the Company. In the study, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins (2011) 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.[49]

Q73. Have regulators in other jurisdictions made a specific risk adjustment to the cost of equity results based on a company's small size?

A73. Yes. For example, 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

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[46] Thomas M. Zepp, "Utility Stocks and the Size Effect—Revisited," *The Quarterly Review of Economics and Finance*. Vol. 43, No. 3, 2003, at 578-582.

[47] *Id*.

[48] Stéphane Chrétien and Frank Coggins, "Cost Of Equity For Energy Utilities: Beyond The CAPM," *Energy Studies Review*, Vol. 18, No. 2, 2011.

[49] *Id.*

"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."[50] Thus, the RCA awarded AEL&P an ROE of 12.875 percent, which was 108 basis points above the highest cost of equity estimate from any model presented in the case.[51] Similarly, the RCA has also 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.[52] 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.[53]

Additionally, the Minnesota Public Utilities Commission ("Minnesota PUC") authorized an ROE for Otter Tail Power Company ("Otter Tail") 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.[54]

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[50] Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at 37.

[51] *Id.*, at 32 and 37.

[52] Regulatory Commission of Alaska, Docket No. U-16-066, Order No. 19, September 22, 2017, at 50-52.

[53] Ibid.

[54] 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.

Finally, in Opinion Nos. 569 and 569-A, the Federal Energy Regulatory Commission ("FERC") adopted a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[55]

Q74. How have you considered the smaller size of Montana-Dakota in your recommendation?

A74. 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 have considered the small size of Montana-Dakota's natural gas operations in Montana, along with the other risk factors present for the Company, in determining where, within the range of analytical results, my recommended ROE for the Company should fall.

B. Flotation Cost

Q75. What are flotation costs?

A75. 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.

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[55] *Ass'n. of Businesses Advocating Tariff Equity, et. al., v. Midcontinent Indep. Sys. Operator, Inc., et. al.*, 171 FERC ¶ 61,154 (2020), at ¶ 75. The U.S. Court of Appeals recently vacated FERC Order No. 569 decisions that related to its risk premium model and remanded the case to FERC to reopen the proceedings. However, in its decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. (*See*, United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022 at 20).

Q76. Why is it important to consider flotation costs in the allowed ROE?

A76. 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 (or required) returns, thereby diluting equity share value.

Q77. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A77. 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 rate of return in the future.

Q78. Can you provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested?

A78. Yes. 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.

Q79. Is the date of MDU Resources' last issued common equity important in the determination of flotation costs?

A79. No. As shown in Exhibit No.___(AEB-2), Schedule 10, 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.

Q80. Is the need to consider flotation costs eliminated because Montana-Dakota is a wholly-owned subsidiary of MDU?

A80. No. Although Montana-Dakota is a wholly-owned subsidiary of MDU, it is appropriate to consider flotation costs because wholly-owned subsidiaries receive equity capital from their parent and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based upon the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund the utility operations and could inhibit the utility's ability to obtain new equity capital at a reasonable cost.

Q81. Is the need to consider flotation costs recognized by the academic and financial communities?

A81. Yes. 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 rate of return. 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.[56]

[56] Shannon P. Pratt, *Cost of Capital Estimation and Applications* (2nd ed. 2002), at 220-221.

Q82. How did you calculate the flotation costs for MDU Resources?

A82. 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 issuance. That flotation cost percentage is then applied to the proxy group in the DCF analysis to estimate the impact on the cost of equity associated with flotation costs. As shown in Exhibit No.___(AEB-2), Schedule 10, based on the flotation costs previously incurred by MDU, the average impact on the proxy group's cost of equity is 16 basis points (*i.e.*, 0.16 percent).

Q83. Do your final cost of equity results include an adjustment for flotation cost recovery?

A83. No. While the final ROE results do not incorporate an explicit adjustment for flotation costs, similar to the small size premium, I have considered the effect of flotation costs, along with the other risk factors present for the Company, in determining where, within the range of analytical results, my recommended ROE for the Company should fall.

C. Capital Expenditures

Q84. What are the Company's projected capital expenditure requirements over the next few years?

A84. As of December 31, 2023, the Company had net utility plant of approximately $107.5 million, and the Company currently projects capital expenditures for 2024 through 2028 of approximately $142 million,[57] which represent approximately 132 percent of its current net utility plant.

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[57] Data provided by the Company.

Q85. How do Montana-Dakota's capital expenditure requirements compare to those of the proxy group companies?

A85. As shown Exhibit No.___(AEB-2), Schedule 11, I have calculated the ratio of expected capital expenditures to net utility plant for Montana-Dakota and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2024 through 2028 by its total net utility plant as of December 31, 2023. As shown, Montana-Dakota's ratio of capital expenditures as a percentage of net utility plant is substantially higher than the median for the proxy group companies, and in fact, is the highest amongst the proxy group companies.

Q86. How is the Company's risk profile affected by their substantial capital expenditure requirements?

A86. 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.

Q87. Do credit rating agencies recognize the risks associated with significant capital expenditures?

A87. Yes. 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 a significant amount of 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 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.[58]

Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the balance between operating with negative discretionary cash flow from operations offset by reliable access to capital markets for financing may be tested through ever-increasing capital expenditure requirements as a result of the transformation of the energy sector through the focus on low/no carbon generation, electrification, and the replacement of aging infrastructure:

> Some companies have been unable to support financial metrics consistent with former ratings as their discretionary cash flow deteriorated. This trend was a significant contributor to the sector seeing the median rating decline to 'BBB+' from 'A-' for the first time in 2022. What is less clear is whether or not management teams will take steps to forestall another step down in credit quality as high capital outlays persist. So far in 2023, we have not seen evidence that equity issuance is keeping pace with debt issuance to fill ever-deepening discretionary cash flow shortfalls, but time will tell.
>
> …..
>
> Despite the improvement in the economic outlook, we expect inflation, high interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. We are cautious about the durability of the current stable ratings outlook given persistently high capital spending that now supports a trend of

[58] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

> deterioration in discretionary cash flow. Without a commensurate focus on balance sheet preservation through equity support of discretionary cash flow deficits, limited financial cushions could give rise to another round of negative rating actions. The question then comes back to management priorities and financial policy decisions, or utilities may be faced with another step down in the median ratings. [59]

Therefore, to the extent that Montana-Dakota's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q88. Does the Company currently have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A88. No. Montana-Dakota currently has not requested approval to 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 capital programs like Montana-Dakota's generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit No.___(AEB-2), Schedule 12, approximately 71 percent of the companies in the proxy group currently have mechanisms for some form of capital cost recovery in place.

Q89. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A89. Since Montana-Dakota has the most significant projected capital expenditure program relative to net utility plant of the proxy group over the next five years, and unlike a number of the operating subsidiaries of the proxy group does not currently have a capital tracking

59 S&P Global Ratings, "Record CapEx Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities," September 12, 2023, at 5, 7-8.

mechanism, this results in a risk profile for the Company that is greater than that of the proxy group, all else being equal.

D. Regulatory Risk

Q90. How does the regulatory environment affect investors' risk assessments?

A90. 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 commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms, and that doing so balances the long-term interests of investors and customers. Utilities must finance their operations and thus require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. The Company is no exception. Therefore, 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, a 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 (*i.e.*, 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.

Q91. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A91. Yes. 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.[60]

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."[61] 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)

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[60] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

[61] 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.

tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[62]

Q92. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A92. 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, for utilities, which are rate regulated, "the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[63] 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."[64]

Q93. Have you conducted an analysis to compare the cost recovery mechanisms of Montana-Dakota to the cost recovery mechanisms approved in the jurisdictions in which the companies in your proxy group operate?

A93. Yes. I have evaluated the regulatory framework in Montana based on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (*i.e.*, forecast vs. historical); (2) use of rate design

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[62] *Id.*, at 1.
[63] Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," June 23, 2017, at 6.
[64] *Id.*

or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases. Each are described below and are summarized in Exhibit No.___(AEB-2), Schedule 12 and are summarized below.

Test Year Convention: Montana-Dakota uses a historical test year adjusted for known and measurable changes in Montana, while, over half of the utility operating subsidiaries of the companies in the proxy group also use either fully forecasted or partially forecasted test years. Forecast test years have been relied on for several years and produce cost estimates that are more reflective of future costs which results in more accurate recovery of incurred costs and mitigates the regulatory lag associated with historical test years. As Lowry, Hovde, Getachew, and Makos explain in their 2010 report, *Forward Test Years for US Electric Utilities*:

> This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future.[65]

Volumetric Risk: Montana-Dakota does not have protection against volumetric risk in Montana, either through a revenue decoupling mechanism, formula rate plan or straight fixed-variable rate design. However, approximately 91 percent of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization

[65] M.N. Lowry, D. Hovde, L. Getachew, and M. Makos, Forward Test Years for US Electric Utilities, prepared for Edison Electric Institute, August 2010, at 1.

through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.

Capital Cost Recovery: As noted previously, Montana-Dakota does not have a capital tracking mechanism to recover capital investment costs between rate cases. However, approximately 71 percent of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism.

Q94. Have you developed any additional analyses to evaluate the regulatory environment in Montana as compared to the jurisdictions in which the companies in your proxy group operate?

A94. Yes. I have conducted two additional analyses to compare the regulatory framework of Montana to the jurisdictions in which the companies in the proxy group operate. Specifically, I have considered two different rankings: (1) the RRA ranking of regulatory jurisdictions; and (2) S&P's ranking of the credit supportiveness of regulatory jurisdictions.

Q95. How does RRA evaluate the regulatory environment in each jurisdiction?

A95. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies that are regulated in each jurisdiction. RRA considers several factors that affect the regulatory process, including gubernatorial, legislative and court activity, rate case decisions and other regulatory decisions, and information obtained through contact with commissioners, staff, utilities, and government outreach.

Q96. How do you use the RRA ratings to compare the regulatory jurisdictions of the proxy group companies with the Company's regulatory jurisdiction?

A96. RRA assigns a ranking for each regulatory jurisdiction as "Above Average", "Average" or "Below Average", and then within each of those categories, a numeric ranking from 1 to 3. Thus, there are a total of nine RRA rankings, with the rankings for each jurisdiction ranging from "Above Average/1", which is considered the most supportive, to "Below Average/3," which is the least supportive. I have applied a numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest ranking (*i.e.*, a "1") and "Below Average/3" assigned the lowest ranking (*i.e.*, a "9").

As shown on Exhibit No.___(AEB-2), Schedule 13, the Montana jurisdictional ranking is "Below Average / 1" (*i.e.*, a "7"), which is well below the proxy group average ranking of between of "Average/1 to Average/2" (*i.e.*, a "4.74").

Q97. How do you conduct your analysis of the S&P credit supportiveness ranking?

A97. For credit supportiveness, S&P classifies each regulatory jurisdiction into five categories ranging from "Most Credit Supportive" down to "Credit Supportive." My analysis of the credit supportiveness of the regulatory jurisdictions in which the proxy companies operate as compared to the Company's regulatory jurisdiction is similar to the analysis of the RRA overall regulatory ranking discussed above. Specifically, I have assigned a numerical ranking to each category, from Most Credit Supportive (*i.e.*, a "1") to Credit Supportive (*i.e.*, a "5").

As shown on Exhibit No.___(AEB-2), Schedule 14, S&P ranks Montana as "More Credit Supportive" (*i.e.*, a "4"), which is well below the proxy group average ranking of "2.26."

Q98. What are your conclusions regarding the perceived risks related to the regulatory environment in Montana?

A98. 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 of the Company relative to the proxy group, many of the companies in the proxy group have more timely capital cost recovery between rate proceeding. In addition, the RRA jurisdictional ranking and the S&P credit supportiveness ranking for Montana indicate greater than average risk relative to the proxy group. For these reasons, I conclude that Montana-Dakota has greater than average regulatory risk relative to the proxy group. Therefore, the average ROE for the proxy group would understate the ROE that an investor would require in Montana because the risks of timely and full cost recovery are greater for Montana-Dakota in Montana as compared to the other utilities of the proxy group.

VIII. CAPITAL STRUCTURE

Q99. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A99. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility. All else equal, a higher debt ratio increases the risk to investors. Specifically, 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. Further, the incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q100. What is the Company's proposed capital structure?

A100. The Company proposes to establish a capital structure consisting of 50.157 percent common equity, 44.586 percent long-term debt and 5.257 percent short-term debt.

Q101. Did you conduct any analysis to determine if this requested equity ratio was reasonable?

A101. Yes. I compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. The cost of equity is estimated based on the return that is derived from companies in the proxy group that are deemed to be comparable in risk to the Company; however, those companies must be publicly-traded in order to apply the cost of equity models. The operating utility subsidiaries of the proxy group companies are most risk-comparable to the Company, and thus it is reasonable to look to the average capital structure of the operating utilities of the proxy group to benchmark the equity ratios for the Company. Specifically, I have calculated the average proportion of common equity, long-term debt, preferred equity, and short-term debt for the most recent three years for each of the utility operating subsidiaries of the proxy group companies. As shown on Exhibit No.___(AEB-2), Schedule 15, the common equity ratios for operating subsidiaries of the proxy group companies over the past three years ranged from 44.57 percent to 59.79 percent, with an average of 53.59 percent. Therefore, Montana-Dakota's proposed equity ratio is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies, and, in fact, is well below the average.

Q102. Are there other factors to be considered in setting the Company's capital structure?

A102. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities.

For example, while Moody's recently revised its outlook for the utility sector from "negative" to "stable", Moody's continues to note that high interest rates and increased capital spending will place pressure on credit metrics. Thus, Moody's highlights constructive regulatory outcomes that promote timely cost recovery as a key factor in supporting utility credit quality. [66]

S&P also recently revised its outlook for the industry; however, S&P downgraded its outlook from stable to negative.[67] S&P noted that for the fifth consecutive year it expects downgrades will exceed upgrades with the industry facing significant risks over the near-term as a result of physical risks due to climate change, increased levels of capital spending and cash-flow deficits that are not being "funded in a sufficiently credit supportive manner".[68] In regard to the effect of increased capital spending, S&P noted:

> The industry's capital spending remains at record levels, supporting initiatives for safety, reliability, energy transition, and growth. We consider these trends long term and expect that capital spending will only continue to increase over this decade.
>
> Accordingly, cash flow deficits have increased, pressuring the industry's credit quality. For 2024, our base case assumes that the industry will fund

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[66] Moody's Investors Service, Outlook, "Outlook turns stable on low prices and credit-supportive regulation," September 7, 2023.

[67] S&P Global Ratings, "Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens, February 14, 2024.

[68] *Id.*

> its approximate $85 billion of cash flow deficits with about $40 billion in asset sales and equity issuance.
>
> For 2023, the industry's actual equity issuance was considerably below our expectations, resulting in a weakening of financial performance and credit quality. If this trend persists, credit quality will again likely experience pressure in 2024.[69]

Fitch Ratings ("Fitch") has stated that it is maintaining a "deteriorating outlook" on the U.S. utility sector in 2024 based on elevated capital spending and continuing higher interest rates that place pressure on credit metrics. Fitch notes that bill affordability will remain a major issue for the industry that could affect future regulatory outcomes, and that while it expects authorized ROEs to start trending up with the increase in interest rates, albeit with a lag, given the uncertain macroeconomic environment and bill pressure on customers, the lag could be longer than in previous cycles.[70]

The credit ratings agencies' continued concerns over the negative effects of inflation, higher interest rates, and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the Company in the context of this proceeding.

Q103. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A103. Yes. The level of earnings authorized by the Commission directly affects the Company's ability to fund its operations with internally-generated funds. Both bond investors and rating agencies expect a significant portion of ongoing capital investments to be financed with internally-generated funds. In addition, it is important to recognize that because a utility's investment horizon is very long, investors require the assurance of a sufficiently

69 *Id.* at 6-8.

70 FitchRatings, "North American Utilities, Power & Gas Outlook," S&P Market Intelligence, November 13, 2023.

high return to satisfy the long-term financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally-generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. As a consequence, both the ROE and capital structure are very important to debt and equity investors, particularly given the capital market conditions discussed previously.

IX. CONCLUSION AND RECOMMENDATION

Q104. What is your conclusion regarding a fair ROE for Montana-Dakota?

A104. 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 current and prospective conditions in capital markets, it is my view that an ROE of 10.80 percent is reasonable and would fairly balance the interests of customers and shareholders. Figure 12 summarizes the results of my cost of equity analyses. 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 current and prospective conditions in capital markets, it is my view that an ROE of 10.80 percent is reasonable and would fairly balance the interests of customers and shareholders.

Figure 12: Summary of Analytical Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.00%	10.11%	11.24%
90-Day Avg. Stock Price	9.13%	10.24%	11.37%
180-Day Avg. Stock Price	9.17%	10.27%	11.41%
Average	9.10%	10.21%	11.34%
Median Results:			
30-Day Avg. Stock Price	9.52%	9.99%	11.43%
90-Day Avg. Stock Price	9.66%	10.07%	11.57%
180-Day Avg. Stock Price	9.72%	10.10%	11.62%
Average	9.63%	10.05%	11.54%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.49%	11.46%	11.45%
Current Bloomberg Beta	10.61%	10.55%	10.53%
Long-term Avg. *Value Line* Beta	10.46%	10.39%	10.37%
ECAPM:			
Current *Value Line* Beta	11.75%	11.72%	11.71%
Current Bloomberg Beta	11.09%	11.04%	11.02%
Long-term Avg. *Value Line* Beta	10.97%	10.92%	10.90%
Bond Yield Risk Premium	10.56%	10.41%	10.35%

Q105. What is your conclusion regarding the Company's proposed capital structure?

A105. The Company's proposed capital structure consisting of 50.157 percent common equity, 44.586 percent long-term debt, and 5.257 percent short-term debt is reasonable when compared to the capital structures of the companies in the proxy group. Further, considering the impact of current and projected market conditions on the cash flows of utilities as raised by the credit rating agencies, the Company's proposed capital structure is reasonable and should be adopted for ratemaking purposes.

Q106. Does this conclude you direct testimony?

A106. Yes.

Ann E. Bulkley

PRINCIPAL

Boston | 508.981.0866 | Ann.Bulkley@brattle.com

With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- 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
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have 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. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff and prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have 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. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- 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, and 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.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- 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 and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have 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.

BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Southwest Gas Corporation	02/24	Southwest Gas Corporation	Docket No. G-01551A-23-0341	Return on Equity
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
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				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of Colorado	01/24	Public Service Company of Colorado	Docket No. 24AL-___G	Return on Equity
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
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				
The Southern Connecticut Gas Company	11/23	The Southern Connecticut Gas Company	Docket No. 23-11-02	Return on Equity
Connecticut Natural Gas Corporation	11/23	Connecticut Natural Gas Corporation	Docket No. 23-11-02	Return on Equity
Connecticut Water Company	10/23	Connecticut Water Company	Docket No. 23-08-32	Return on Equity
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
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
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	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Illinois American Water	01/24	Illinois American Water	Docket No. 24-0097	Return on Equity
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	02/24	Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	Cause No. 46011	Return on Equity
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	12/23	Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	IURC Cause No. 45990	Return on Equity
Indiana Michigan Power Co.	08/23	Indiana Michigan Power Co.	IURC Cause No. 45933	Return on Equity
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
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
Iowa Department of Commerce Utilities Board				
Iowa-American Water Company	04/24	Iowa-American Water Company	Docket No. RPU-2024-000_	Return on Equity
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-____	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	04/23	Evergy Kansas	Docket No. 23-EKCE-775-RTS	Return on Equity
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	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	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
Massachusetts Department of Public Utilities				
Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	11/23	Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	DPU 23-150	Return on Equity
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
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				
Upper Michigan Energy Resources Corporation	05/24	Upper Michigan Energy Resources Corporation	Case No. U-21541	Return on Equity
Michigan Gas Utilities Corporation	03/24	Michigan Gas Utilities Corporation	Case No. U-21540	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana Michigan Power Co.	09/23	Indiana Michigan Power Co.	Case No. U-21461	Return on Equity
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
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	11/23	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-23-155	Return on Equity
CenterPoint Energy Resources	11/23	CenterPoint Energy Resources	D-G-008/GR-23-173	Return on Equity
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
Evergy Missouri West	02/24	Evergy Missouri West	File No. ER-2024-0189	Return on Equity
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	01/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	01/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
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.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
Public Utilities Commission of Nevada				
Sierra Pacific Power Company d/b/a NV Energy	02/24	Sierra Pacific Power Company d/b/a NV Energy	24-02026	Return on Equity
Nevada Power Company d/b/a NV Energy	06/23	Nevada Power Company d/b/a NV Energy	23-06007	Return on Equity
Nevada Power Company d/b/a NV Energy	03/23	Nevada Power Company d/b/a NV Energy	22-03028	Merger benefits
New Hampshire - Board of Tax and Land Appeals				
Liberty Utilities (EnergyNorth Natural Gas)	07/23	Liberty Utilities (EnergyNorth Natural Gas)	Docket No. DG 23-067	Return on Equity
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity
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
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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.	02/24	New Jersey American Water Company, Inc.	WR2401056	Return on Equity
Elizabethtown Gas Company	2/24	Elizabethtown Gas Company	GR24020158	Return on Equity
Public Service Electric and Gas Company	12/23	Public Service Electric and Gas Company	ER23120924 GR23120925	Return on Equity
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New York State Department of Public Service				
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-W-0235	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
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
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	Electric 17-E-0459 Gas 17-G-0460	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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/23	Otter Tail Power Company	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	11/23	Montana-Dakota Utilities Co.	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
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				
Oklahoma Gas & Electric	12/23	Oklahoma Gas & Electric	Cause No. PUD2023-000087	Return on Equity
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
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	02/24	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-433	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	11/23	Pennsylvania-American Water Company	Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater)	Return on Equity
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
CenterPoint Energy Houston	03/24	CenterPoint Energy Houston	D-56211	Return on Equity
AEP Texas	02/24	AEP Texas	D-56165	Return on Equity
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
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
Texas Railroad Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
CenterPoint Energy Entex and CenterPoint Energy Texas Gas	10/23	CenterPoint Energy Entex and CenterPoint Energy Texas Gas	2023 Texas Division Rate Case Case No. OS-23-00015513	Return on Equity
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.	11/23	Virginia American Water Company, Inc.	Docket No. PUR-2023-00194	Return on Equity
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
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	03/24	Cascade Natural Gas Corporation	Docket No. UG-240008	Return on Equity
Puget Sound Energy Inc.	02/24	Puget Sound Energy Inc.	Docket No. UE-240004 UG-240005	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
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	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
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 Power and Light	04/24	Wisconsin Power and Light	Docket No. 6680-UR-128	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/24	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-111	Return on Equity
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
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	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
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

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.00%	10.11%	11.24%
90-Day Avg. Stock Price	9.13%	10.24%	11.37%
180-Day Avg. Stock Price	9.17%	10.27%	11.41%
Average	9.10%	10.21%	11.34%
Median Results:			
30-Day Avg. Stock Price	9.52%	9.99%	11.43%
90-Day Avg. Stock Price	9.66%	10.07%	11.57%
180-Day Avg. Stock Price	9.72%	10.10%	11.62%
Average	9.63%	10.05%	11.54%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.49%	11.46%	11.45%
Current Bloomberg Beta	10.61%	10.55%	10.53%
Long-term Avg. *Value Line* Beta	10.46%	10.39%	10.37%
ECAPM:			
Current *Value Line* Beta	11.75%	11.72%	11.71%
Current Bloomberg Beta	11.09%	11.04%	11.02%
Long-term Avg. *Value Line* Beta	10.97%	10.92%	10.90%
Bond Yield Risk Premium	10.56%	10.41%	10.35%

PROXY GROUP SCREENING DATA AND RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	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	Yes	100.00%	66.30%	No
NiSource Inc.	NI	Yes	BBB+	Yes	Yes	99.89%	67.83%	No
Northwest Natural Gas Company	NWN	Yes	A	Yes	Yes	100.00%	90.55%	No
ONE Gas, Inc.	OGS	Yes	A-	Yes	Yes	100.00%	100.00%	No
Spire, Inc.	SR	Yes	BBB+	Yes	Yes	83.38%	100.00%	No

Notes:
[1] Bloomberg Professional
[2] Bloomberg Professional
[3] Yahoo! Finance and Zacks
[4] Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Form 10-K's for 2023, 2022, and 2021
[6] Form 10-K's for 2023, 2022, and 2021
[7] S&P Capital IQ Pro Financial News Releases

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$116.59	2.76%	2.86%	7.00%	7.40%	7.00%	7.13%	9.86%	9.99%	10.26%
NiSource Inc.	NI	$1.06	$28.41	3.73%	3.87%	9.50%	7.40%	6.00%	7.63%	9.84%	11.51%	13.41%
Northwest Natural Gas Company	NWN	$1.95	$37.86	5.15%	5.27%	6.50%	2.80%	n/a	4.65%	8.02%	9.92%	11.82%
ONE Gas, Inc.	OGS	$2.64	$63.07	4.19%	4.28%	3.50%	5.00%	5.00%	4.50%	7.76%	8.78%	9.29%
Spire, Inc.	SR	$3.02	$61.46	4.91%	5.04%	4.50%	6.36%	5.00%	5.29%	9.52%	10.33%	11.43%
Mean				4.15%	4.27%	6.20%	5.79%	5.75%	5.84%	9.00%	10.11%	11.24%
Median				4.19%	4.28%	6.50%	6.36%	5.50%	5.29%	9.52%	9.99%	11.43%

Notes:
[1] Bloomberg Professional as of May 31, 2024
[2] Bloomberg Professional 30-day average as of May 31, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$114.55	2.81%	2.91%	7.00%	7.40%	7.00%	7.13%	9.91%	10.04%	10.31%
NiSource Inc.	NI	$1.06	$26.92	3.94%	4.09%	9.50%	7.40%	6.00%	7.63%	10.06%	11.72%	13.62%
Northwest Natural Gas Company	NWN	$1.95	$36.82	5.30%	5.42%	6.50%	2.80%	n/a	4.65%	8.17%	10.07%	11.97%
ONE Gas, Inc.	OGS	$2.64	$61.53	4.29%	4.39%	3.50%	5.00%	5.00%	4.50%	7.87%	8.89%	9.40%
Spire, Inc.	SR	$3.02	$59.85	5.05%	5.18%	4.50%	6.36%	5.00%	5.29%	9.66%	10.47%	11.57%
Mean				4.28%	4.40%	6.20%	5.79%	5.75%	5.84%	9.13%	10.24%	11.37%
Median				4.29%	4.39%	6.50%	6.36%	5.50%	5.29%	9.66%	10.07%	11.57%

Notes:
[1] Bloomberg Professional as of May 31, 2024
[2] Bloomberg Professional 90-day average as of May 31, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$112.43	2.86%	2.97%	7.00%	7.40%	7.00%	7.13%	9.96%	10.10%	10.37%
NiSource Inc.	NI	$1.06	$26.14	4.06%	4.21%	9.50%	7.40%	6.00%	7.63%	10.18%	11.84%	13.75%
Northwest Natural Gas Company	NWN	$1.95	$37.02	5.27%	5.39%	6.50%	2.80%	n/a	4.65%	8.14%	10.04%	11.94%
ONE Gas, Inc.	OGS	$2.64	$62.03	4.26%	4.35%	3.50%	5.00%	5.00%	4.50%	7.83%	8.85%	9.36%
Spire, Inc.	SR	$3.02	$59.18	5.10%	5.24%	4.50%	6.36%	5.00%	5.29%	9.72%	10.52%	11.62%
Mean				4.31%	4.43%	6.20%	5.79%	5.75%	5.84%	9.17%	10.27%	11.41%
Median				4.26%	4.35%	6.50%	6.36%	5.50%	5.29%	9.72%	10.10%	11.62%

Notes:
[1] Bloomberg Professional as of May 31, 2024
[2] Bloomberg Professional 180-day average as of May 31, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[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	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.66%	0.85	12.51%	7.86%	11.34%	11.63%
NiSource Inc.	NI	4.66%	0.95	12.51%	7.86%	12.12%	12.22%
Northwest Natural Gas Company	NWN	4.66%	0.85	12.51%	7.86%	11.34%	11.63%
ONE Gas, Inc.	OGS	4.66%	0.85	12.51%	7.86%	11.34%	11.63%
Spire, Inc.	SR	4.66%	0.85	12.51%	7.86%	11.34%	11.63%
Mean						11.49%	11.75%
Median						11.34%	11.63%

Notes:
[1] Bloomberg Professional 30-day average as of May 31, 2024
[2] Value Line
[3] Market Return
[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 AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2024 - Q3 2025)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.40%	0.85	12.51%	8.11%	11.30%	11.60%
NiSource Inc.	NI	4.40%	0.95	12.51%	8.11%	12.11%	12.21%
Northwest Natural Gas Company	NWN	4.40%	0.85	12.51%	8.11%	11.30%	11.60%
ONE Gas, Inc.	OGS	4.40%	0.85	12.51%	8.11%	11.30%	11.60%
Spire, Inc.	SR	4.40%	0.85	12.51%	8.11%	11.30%	11.60%
Mean						11.46%	11.72%
Median						11.30%	11.60%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 2
[2] Value Line
[3] Market Return
[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 AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.85	12.51%	8.21%	11.28%	11.59%
NiSource Inc.	NI	4.30%	0.95	12.51%	8.21%	12.10%	12.21%
Northwest Natural Gas Company	NWN	4.30%	0.85	12.51%	8.21%	11.28%	11.59%
ONE Gas, Inc.	OGS	4.30%	0.85	12.51%	8.21%	11.28%	11.59%
Spire, Inc.	SR	4.30%	0.85	12.51%	8.21%	11.28%	11.59%
Mean						11.45%	11.71%
Median						11.28%	11.59%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14
[2] Value Line
[3] Market Return
[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 AND BLOOMBERG BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[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	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.66%	0.75	12.51%	7.86%	10.55%	11.04%
NiSource Inc.	NI	4.66%	0.80	12.51%	7.86%	10.97%	11.35%
Northwest Natural Gas Company	NWN	4.66%	0.70	12.51%	7.86%	10.13%	10.72%
ONE Gas, Inc.	OGS	4.66%	0.77	12.51%	7.86%	10.73%	11.17%
Spire, Inc.	SR	4.66%	0.77	12.51%	7.86%	10.69%	11.14%
Mean						10.61%	11.09%
Median						10.69%	11.14%

Notes:
[1] Bloomberg Professional 30-day average as of May 31, 2024
[2] Bloomberg Professional
[3] Market Return
[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 AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2024 - Q3 2025)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.40%	0.75	12.51%	8.11%	10.48%	10.99%
NiSource Inc.	NI	4.40%	0.80	12.51%	8.11%	10.92%	11.31%
Northwest Natural Gas Company	NWN	4.40%	0.70	12.51%	8.11%	10.05%	10.67%
ONE Gas, Inc.	OGS	4.40%	0.77	12.51%	8.11%	10.67%	11.13%
Spire, Inc.	SR	4.40%	0.77	12.51%	8.11%	10.63%	11.10%
Mean						10.55%	11.04%
Median						10.63%	11.10%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 2
[2] Bloomberg Professional
[3] Market Return
[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 AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.75	12.51%	8.21%	10.46%	10.97%
NiSource Inc.	NI	4.30%	0.80	12.51%	8.21%	10.90%	11.30%
Northwest Natural Gas Company	NWN	4.30%	0.70	12.51%	8.21%	10.02%	10.64%
ONE Gas, Inc.	OGS	4.30%	0.77	12.51%	8.21%	10.65%	11.11%
Spire, Inc.	SR	4.30%	0.77	12.51%	8.21%	10.60%	11.08%
Mean						10.53%	11.02%
Median						10.60%	11.08%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14
[2] Bloomberg Professional
[3] Market Return
[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 AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[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	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.66%	0.75	12.51%	7.86%	10.55%	11.04%
NiSource Inc.	NI	4.66%	0.76	12.51%	7.86%	10.59%	11.07%
Northwest Natural Gas Company	NWN	4.66%	0.71	12.51%	7.86%	10.23%	10.80%
ONE Gas, Inc.	OGS	4.66%	0.74	12.51%	7.86%	10.45%	10.97%
Spire, Inc.	SR	4.66%	0.74	12.51%	7.86%	10.48%	10.99%
Mean						10.46%	10.97%
Median						10.48%	10.99%

Notes:
[1] Bloomberg Professional 30-day average as of May 31, 2024
[2] Source: LT Beta
[3] Market Return
[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 AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2024 - Q3 2025)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.40%	0.75	12.51%	8.11%	10.49%	10.99%
NiSource Inc.	NI	4.40%	0.76	12.51%	8.11%	10.53%	11.03%
Northwest Natural Gas Company	NWN	4.40%	0.71	12.51%	8.11%	10.15%	10.74%
ONE Gas, Inc.	OGS	4.40%	0.74	12.51%	8.11%	10.38%	10.92%
Spire, Inc.	SR	4.40%	0.74	12.51%	8.11%	10.41%	10.94%
Mean						10.39%	10.92%
Median						10.41%	10.94%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 2
[2] Source: LT Beta
[3] Market Return
[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 AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.75	12.51%	8.21%	10.46%	10.97%
NiSource Inc.	NI	4.30%	0.76	12.51%	8.21%	10.51%	11.01%
Northwest Natural Gas Company	NWN	4.30%	0.71	12.51%	8.21%	10.12%	10.72%
ONE Gas, Inc.	OGS	4.30%	0.74	12.51%	8.21%	10.36%	10.90%
Spire, Inc.	SR	4.30%	0.74	12.51%	8.21%	10.39%	10.92%
Mean						10.37%	10.90%
Median						10.39%	10.92%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL BETA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	Average
Atmos Energy Corporation	ATO	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.80	0.80	0.85	0.75
NiSource Inc.	NI	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.85	0.85	0.90	0.76
Northwest Natural Gas Company	NWN	0.65	0.70	0.65	0.65	0.70	0.60	0.60	0.80	0.85	0.80	0.80	0.71
ONE Gas, Inc.	OGS				0.70	0.70	0.65	0.65	0.80	0.80	0.80	0.80	0.74
Spire, Inc.	SR	0.65	0.70	0.70	0.70	0.70	0.65	0.65	0.85	0.85	0.85	0.85	0.74
Mean		0.74	0.76	0.72	0.69	0.68	0.60	0.61	0.82	0.83	0.82	0.84	0.74

Notes:
[1] Value Line, December 26, 2013
[2] Value Line, December 31, 2014
[3] Value Line, December 30, 2015
[4] Value Line, December 29, 2016
[5] Value Line, December 28, 2017
[6] Value Line, December 27, 2018
[7] Value Line, December 26, 2019
[8] Value Line, December 30, 2020
[9] Value Line, December 29, 2021
[10] Value Line, December 30, 2022
[11] Value Line, December 29, 2023
[11] Average ([1] - [11])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.60%
[2] Estimate of the S&P 500 Growth Rate	10.83%
[3] S&P 500 Estimated Required Market Return	12.51%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	325.622	98.08	31,937.01	0.10%	5.46%	0.01%	10.72%	0.01%
American Express Co	AXP	719.303	240	172,632.72	0.51%	1.17%	0.01%	15.23%	0.08%
Verizon Communications Inc	VZ	4209.255	41.15	173,210.84	0.52%	6.46%	0.03%	1.22%	0.01%
Broadcom Inc	AVGO	463.421	1328.55	615,677.97	1.83%	1.58%	0.03%	14.54%	0.27%
Boeing Co/The	BA	613.884	177.61	109,031.94				50.92%	
Solventum Corp	SOLV	172.71	59.34	10,248.61					
Caterpillar Inc	CAT	489.053	338.52	165,554.22	0.49%	1.54%	0.01%	7.70%	0.04%
JPMorgan Chase & Co	JPM	2871.668	202.63	581,886.09	1.73%	2.27%	0.04%	3.03%	0.05%
Chevron Corp	CVX	1847.32	162.3	299,820.04		4.02%			
Coca-Cola Co/The	KO	4307.955	62.93	271,099.61	0.81%	3.08%	0.02%	6.36%	0.05%
AbbVie Inc	ABBV	1765.868	161.24	284,728.56	0.85%	3.85%	0.03%	8.34%	0.07%
Walt Disney Co/The	DIS	1823.043	103.91	189,432.40		0.87%		20.89%	
Corpay Inc	CPAY	70.269	267.67	18,808.90	0.06%			14.22%	0.01%
Extra Space Storage Inc	EXR	211.725	144.77	30,651.43	0.09%	4.48%	0.00%	1.86%	0.00%
Exxon Mobil Corp	XOM	4485.928	117.26	526,019.92	1.57%	3.24%	0.05%	6.00%	0.09%
Phillips 66	PSX	423.952	142.11	60,247.82		3.24%			
General Electric Co	GE	1094.607	165.14	180,763.40		0.68%		32.59%	
HP Inc	HPQ	978.56	36.5	35,717.44	0.11%	3.02%	0.00%	5.12%	0.01%
Home Depot Inc/The	HD	991.614	334.87	332,061.78	0.99%	2.69%	0.03%	3.43%	0.03%
Monolithic Power Systems Inc	MPWR	48.672	735.63	35,804.58	0.11%	0.68%	0.00%	18.00%	0.02%
International Business Machines Corp	IBM	918.603	166.85	153,268.91	0.46%	4.00%	0.02%	3.19%	0.01%
Johnson & Johnson	JNJ	2406.679	146.67	352,987.61	1.05%	3.38%	0.04%	4.99%	0.05%
Lululemon Athletica Inc	LULU	120.892	311.99	37,717.10	0.11%			9.86%	0.01%
McDonald's Corp	MCD	720.682	257.22	185,373.82	0.55%	2.60%	0.01%	7.51%	0.04%
Merck & Co Inc	MRK	2532.806	125.54	317,968.47		2.45%		53.01%	
3M Co	MMM	553.361	100.14	55,413.57		2.80%		-7.15%	
American Water Works Co Inc	AWK	194.823	130.77	25,477.00	0.08%	2.34%	0.00%	7.70%	0.01%
Bank of America Corp	BAC	7820.37	39.99	312,736.60		2.40%		-6.00%	
Pfizer Inc	PFE	5666.593	28.66	162,404.56	0.48%	5.86%	0.03%	8.39%	0.04%
Procter & Gamble Co/The	PG	2360.135	164.54	388,336.61	1.16%	2.45%	0.03%	8.09%	0.09%
AT&T Inc	T	7170.165	18.22	130,640.41	0.39%	6.09%	0.02%	2.55%	0.01%
Travelers Cos Inc/The	TRV	228.993	215.7	49,393.79	0.15%	1.95%	0.00%	18.34%	0.03%
RTX Corp	RTX	1329.506	107.81	143,334.04	0.43%	2.34%	0.01%	10.62%	0.05%
Analog Devices Inc	ADI	496.217	233.561	115,896.94		1.58%		-2.75%	
Walmart Inc	WMT	8058.049	65.76	529,897.30	1.58%	1.26%	0.02%	8.23%	0.13%
Cisco Systems Inc	CSCO	4049.187	46.5	188,287.20	0.56%	3.44%	0.02%	0.93%	0.01%
Intel Corp	INTC	4256.872	30.85	131,324.50	0.39%	1.62%	0.01%	11.40%	0.04%
General Motors Co	GM	1140.395	44.99	51,306.37	0.15%	1.07%	0.00%	16.07%	0.02%
Microsoft Corp	MSFT	7432.306	415.13	3,085,373.19	9.19%	0.72%	0.07%	14.81%	1.36%
Dollar General Corp	DG	219.895	136.91	30,105.82		1.72%		-2.08%	
Cigna Group/The	CI	284.074	343.2071	97,496.21	0.29%	1.63%	0.00%	11.65%	0.03%
Kinder Morgan Inc	KMI	2219.384	19.49	43,255.79	0.13%	5.90%	0.01%	5.86%	0.01%
Citigroup Inc	C	1907.44	62.31	118,852.59		3.40%		26.67%	
American International Group Inc	AIG	663.668	78.82	52,310.31	0.16%	2.03%	0.00%	11.85%	0.02%
Altria Group Inc	MO	1717.626	46.25	79,440.20	0.24%	8.48%	0.02%	3.89%	0.01%
HCA Healthcare Inc	HCA	261.914	339.75	88,985.28	0.27%	0.78%	0.00%	9.57%	0.03%
International Paper Co	IP	347.332	45.09	15,661.20		4.10%		-2.00%	
Hewlett Packard Enterprise Co	HPE	1300	17.65	22,945.00	0.07%	2.95%	0.00%	2.86%	0.00%
Abbott Laboratories	ABT	1739.634	102.19	177,773.20	0.53%	2.15%	0.01%	8.00%	0.04%
Aflac Inc	AFL	568.222	89.87	51,066.11	0.15%	2.23%	0.00%	7.55%	0.01%
Air Products and Chemicals Inc	APD	222.306	266.7	59,289.01	0.18%	2.65%	0.00%	9.63%	0.02%
Super Micro Computer Inc	SMCI	58.557	784.51	45,938.55				53.18%	
Royal Caribbean Cruises Ltd	RCL	257.349	147.68	38,005.30				29.92%	
Hess Corp	HES	308.109	154.1	47,479.60	0.14%	1.14%	0.00%	18.00%	0.03%
Archer-Daniels-Midland Co	ADM	494.438	62.44	30,872.71		3.20%		-2.85%	
Automatic Data Processing Inc	ADP	409.291	244.92	100,243.55	0.30%	2.29%	0.01%	11.31%	0.03%
Verisk Analytics Inc	VRSK	142.675	252.78	36,065.39	0.11%	0.62%	0.00%	11.71%	0.01%
AutoZone Inc	AZO	17.303	2769.94	47,928.27	0.14%			14.66%	0.02%
Linde PLC	LIN	480.676	434.1263	208,674.09	0.62%	1.28%	0.01%	11.82%	0.07%
Avery Dennison Corp	AVY	80.553	227.59	18,333.06	0.05%	1.55%	0.00%	11.67%	0.01%
Enphase Energy Inc	ENPH	136.063	127.9	17,402.46	0.05%			18.17%	0.01%
MSCI Inc	MSCI	79.224	495.18	39,230.14	0.12%	1.29%	0.00%	11.58%	0.01%
Ball Corp	BALL	310.378	69.23	21,487.47	0.06%	1.16%	0.00%	11.78%	0.01%
Axon Enterprise Inc	AXON	75.467	281.67	21,256.79					
Dayforce Inc	DAY	155.562	49.46	7,694.10					
Carrier Global Corp	CARR	901.012	63.19	56,934.95	0.17%	1.20%	0.00%	7.87%	0.01%
Bank of New York Mellon Corp/The	BK	747.816	59.61	44,577.31	0.13%	2.82%	0.00%	10.01%	0.01%
Otis Worldwide Corp	OTIS	404.323	99.2	40,108.84	0.12%	1.57%	0.00%	9.00%	0.01%
Baxter International Inc	BAX	509.58	34.09	17,371.58	0.05%	3.40%	0.00%	9.78%	0.01%
Becton Dickinson & Co	BDX	289.006	231.97	67,040.72	0.20%	1.64%	0.00%	7.77%	0.02%
Berkshire Hathaway Inc	BRK/B	1311.385	414.4	543,437.94					
Best Buy Co Inc	BBY	215.381	84.82	18,268.62	0.05%	4.43%	0.00%	0.05%	0.00%
Boston Scientific Corp	BSX	1470.18	75.57	111,101.50	0.33%			12.08%	0.04%
Bristol-Myers Squibb Co	BMY	2027.1	41.09	83,293.54		5.84%		-4.12%	
Brown-Forman Corp	BF/B	303.416	45.86	13,914.66	0.04%	1.90%	0.00%	3.39%	0.00%
Coterra Energy Inc	CTRA	744.233	28.52	21,225.53		2.95%			
Campbell Soup Co	CPB	298.103	44.38	13,229.81	0.04%	3.33%	0.00%	4.87%	0.00%
Hilton Worldwide Holdings Inc	HLT	250.046	200.6	50,159.23	0.15%	0.30%	0.00%	15.52%	0.02%
Carnival Corp	CCL	1122.32	15.08	16,924.59					

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Qorvo Inc	QRVO	95.629	98.39	9,408.94				20.04%	
Builders FirstSource Inc	BLDR	122.057	160.79	19,625.55	0.06%			8.54%	0.00%
UDR Inc	UDR	329.307	38.62	12,717.84	0.04%	4.40%	0.00%	1.85%	0.00%
Clorox Co/The	CLX	124.188	131.56	16,338.17	0.05%	3.65%	0.00%	15.46%	0.01%
Paycom Software Inc	PAYC	58.11	145.32	8,444.55	0.03%	1.03%	0.00%	6.00%	0.00%
CMS Energy Corp	CMS	298.635	62.93	18,793.10	0.06%	3.27%	0.00%	7.42%	0.00%
Colgate-Palmolive Co	CL	820.441	92.96	76,268.20	0.23%	2.15%	0.00%	8.36%	0.02%
EPAM Systems Inc	EPAM	57.974	177.93	10,315.31	0.03%			5.54%	0.00%
Comerica Inc	CMA	132.587	51.24	6,793.76	0.02%	5.54%	0.00%	9.79%	0.00%
Conagra Brands Inc	CAG	478.063	29.88	14,284.52	0.04%	4.69%	0.00%	1.82%	0.00%
Airbnb Inc	ABNB	441.5	144.93	63,986.60				20.22%	
Consolidated Edison Inc	ED	344.924	94.55	32,612.56	0.10%	3.51%	0.00%	5.70%	0.01%
Corning Inc	GLW	856.619	37.26	31,917.62	0.10%	3.01%	0.00%	12.03%	0.01%
Cummins Inc	CMI	136.78	281.73	38,535.03	0.11%	2.39%	0.00%	7.56%	0.01%
Caesars Entertainment Inc	CZR	216.416	35.56	7,695.75				-32.44%	
Danaher Corp	DHR	740.687	256.8	190,208.42	0.57%	0.42%	0.00%	3.84%	0.02%
Target Corp	TGT	462.637	156.16	72,245.39	0.22%	2.82%	0.01%	13.97%	0.03%
Deere & Co	DE	275.57	374.76	103,272.61		1.57%		-6.84%	
Dominion Energy Inc	D	837.593	53.92	45,163.01	0.13%	4.95%	0.01%	14.16%	0.02%
Dover Corp	DOV	137.43	183.82	25,262.38	0.08%	1.11%	0.00%	7.56%	0.01%
Alliant Energy Corp	LNT	256.379	51.49	13,200.95	0.04%	3.73%	0.00%	7.00%	0.00%
Steel Dynamics Inc	STLD	157.133	133.87	21,035.39		1.37%		-3.32%	
Duke Energy Corp	DUK	771	103.57	79,852.47	0.24%	3.96%	0.01%	6.53%	0.02%
Regency Centers Corp	REG	184.581	61.4	11,333.27	0.03%	4.36%	0.00%	3.27%	0.00%
Eaton Corp PLC	ETN	399.892	332.85	133,104.05	0.40%	1.13%	0.00%	13.83%	0.05%
Ecolab Inc	ECL	285.57	232.2	66,309.35	0.20%	0.98%	0.00%	17.31%	0.03%
Revvity Inc	RVTY	123.393	109.26	13,481.92	0.04%	0.26%	0.00%	8.26%	0.00%
Emerson Electric Co	EMR	572.1	112.16	64,166.74	0.19%	1.87%	0.00%	15.07%	0.03%
EOG Resources Inc	EOG	574.711	124.55	71,580.26		2.92%			
Aon PLC	AON	217.431	281.64	61,237.27	0.18%	0.96%	0.00%	10.38%	0.02%
Entergy Corp	ETR	213.273	112.49	23,991.08	0.07%	4.02%	0.00%	6.98%	0.00%
Equifax Inc	EFX	123.611	231.39	28,602.35	0.09%	0.67%	0.00%	15.31%	0.01%
EQT Corp	EQT	441.592	41.09	18,145.02		1.53%			
IQVIA Holdings Inc	IQV	182.2	219.09	39,918.20	0.12%			10.44%	0.01%
Gartner Inc	IT	77.63	419.67	32,578.98	0.10%			9.89%	0.01%
FedEx Corp	FDX	246.081	253.96	62,494.73	0.19%	1.98%	0.00%	17.71%	0.03%
FMC Corp	FMC	124.818	60.95	7,607.66	0.02%	3.81%	0.00%	18.88%	0.00%
Brown & Brown Inc	BRO	285.249	89.51	25,532.64	0.08%	0.58%	0.00%	9.77%	0.01%
Ford Motor Co	F	3921.485	12.13	47,567.61	0.14%	4.95%	0.01%	1.67%	0.00%
NextEra Energy Inc	NEE	2055	79.505	163,382.78	0.49%	2.59%	0.01%	8.10%	0.04%
Franklin Resources Inc	BEN	526.091	23.6	12,415.75		5.25%			
Garmin Ltd	GRMN	192.078	163.85	31,471.98	0.09%	1.83%	0.00%	8.04%	0.01%
Freeport-McMoRan Inc	FCX	1436.49	52.73	75,746.12	0.23%	1.14%	0.00%	16.49%	0.04%
Dexcom Inc	DXCM	397.684	118.77	47,232.93				23.63%	
General Dynamics Corp	GD	274.364	299.77	82,246.10	0.24%	1.89%	0.00%	14.18%	0.03%
General Mills Inc	GIS	564.549	68.75	38,812.74		3.43%		0.00%	
Genuine Parts Co	GPC	139.299	144.14	20,078.56		2.78%			
Atmos Energy Corp	ATO	150.877	115.92	17,489.66	0.05%	2.78%	0.00%	7.00%	0.00%
WW Grainger Inc	GWW	49.069	921.46	45,215.12		0.89%			
Halliburton Co	HAL	885.301	36.7	32,490.55	0.10%	1.85%	0.00%	11.60%	0.01%
L3Harris Technologies Inc	LHX	189.68	223.6793	42,427.49	0.13%	2.07%	0.00%	8.53%	0.01%
Healthpeak Properties Inc	DOC	703.782	19.9	14,005.26	0.04%	6.03%	0.00%	4.48%	0.00%
Insulet Corp	PODD	70.04	177.19	12,410.39				28.44%	
Catalent Inc	CTLT	180.98	53.79	9,734.91				28.24%	
Fortive Corp	FTV	352.029	74.44	26,205.04	0.08%	0.43%	0.00%	8.98%	0.01%
Hershey Co/The	HSY	147.616	197.83	29,202.87	0.09%	2.77%	0.00%	2.36%	0.00%
Synchrony Financial	SYF	401.544	43.8	17,587.63		2.28%			
Hormel Foods Corp	HRL	548.305	30.98	16,986.49	0.05%	3.65%	0.00%	6.59%	0.00%
Arthur J Gallagher & Co	AJG	218.5	253.33	55,352.61	0.16%	0.95%	0.00%	12.49%	0.02%
Mondelez International Inc	MDLZ	1341.359	68.53	91,923.33	0.27%	2.48%	0.01%	7.65%	0.02%
CenterPoint Energy Inc	CNP	639.724	30.51	19,517.98	0.06%	2.62%	0.00%	7.95%	0.00%
Humana Inc	HUM	120.501	358.12	43,153.82		0.99%		-1.30%	
Willis Towers Watson PLC	WTW	102.236	255.29	26,099.83	0.08%	1.38%	0.00%	12.41%	0.01%
Illinois Tool Works Inc	ITW	298.4	242.75	72,436.60	0.22%	2.31%	0.00%	7.26%	0.02%
CDW Corp/DE	CDW	134.398	223.62	30,054.08	0.09%	1.11%	0.00%	7.02%	0.01%
Trane Technologies PLC	TT	226.352	327.46	74,121.23	0.22%	1.03%	0.00%	13.47%	0.03%
Interpublic Group of Cos Inc/The	IPG	377.424	31.0361	11,713.77	0.03%	4.25%	0.00%	3.91%	0.00%
International Flavors & Fragrances Inc	IFF	255.351	96.18	24,559.66	0.07%	1.66%	0.00%	0.23%	0.00%
Generac Holdings Inc	GNRC	60.614	147.21	8,922.99	0.03%			7.00%	0.00%
NXP Semiconductors NV	NXPI	255.684	272.1	69,571.62	0.21%	1.49%	0.00%	6.92%	0.01%
Kellanova	K	341.884	59.78	20,437.83	0.06%	3.75%	0.00%	8.42%	0.01%
Broadridge Financial Solutions Inc	BR	118.18	200.77	23,727.00		1.59%			
Kimberly-Clark Corp	KMB	336.709	133.3	44,883.31	0.13%	3.66%	0.00%	7.72%	0.01%
Kimco Realty Corp	KIM	674.116	19.36	13,050.89	0.04%	4.96%	0.00%	3.25%	0.00%
Oracle Corp	ORCL	2748.514	117.19	322,098.36	0.96%	1.37%	0.01%	11.24%	0.11%
Kroger Co/The	KR	721.688	52.37	37,794.80	0.11%	2.22%	0.00%	6.00%	0.01%
Lennar Corp	LEN	245.036	160.35	39,291.52	0.12%	1.25%	0.00%	8.82%	0.01%
Eli Lilly & Co	LLY	950.405	820.34	779,655.24		0.63%		40.01%	
Bath & Body Works Inc	BBWI	223.665	51.94	11,617.16	0.03%	1.54%	0.00%	13.65%	0.00%
Charter Communications Inc	CHTR	144.386	287.12	41,456.11	0.12%			5.89%	0.01%
Loews Corp	L	221.406	76.8	17,003.98		0.33%			
Lowe's Cos Inc	LOW	569.835	221.29	126,098.79	0.38%	2.08%	0.01%	1.52%	0.01%
Hubbell Inc	HUBB	53.686	388.89	20,877.95	0.06%	1.25%	0.00%	18.00%	0.01%
IDEX Corp	IEX	75.695	208.64	15,793.00		1.32%			
Marsh & McLennan Cos Inc	MMC	492.724	207.58	102,279.65	0.30%	1.37%	0.00%	8.12%	0.02%
Masco Corp	MAS	220.244	69.92	15,399.46	0.05%	1.66%	0.00%	8.64%	0.00%
S&P Global Inc	SPGI	320.257	427.51	136,913.07	0.41%	0.85%	0.00%	13.11%	0.05%
Medtronic PLC	MDT	1327.823	81.37	108,044.96	0.32%	3.44%	0.01%	5.61%	0.02%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Viatris Inc	VTRS	1190.676	10.6	12,621.17		4.53%		-2.57%	
CVS Health Corp	CVS	1255.373	59.6	74,820.23	0.22%	4.46%	0.01%	4.01%	0.01%
DuPont de Nemours Inc	DD	418.104	82.16	34,351.42	0.10%	1.85%	0.00%	1.03%	0.00%
Micron Technology Inc	MU	1107.368	125	138,421.00		0.37%		-4.00%	
Motorola Solutions Inc	MSI	166.787	364.91	60,862.24	0.18%	1.07%	0.00%	8.89%	0.02%
Cboe Global Markets Inc	CBOE	105.154	172.99	18,190.59	0.05%	1.27%	0.00%	14.28%	0.01%
Newmont Corp	NEM	1153.163	41.6897	48,075.02		2.40%			
NIKE Inc	NKE	1211.462	94.68	114,701.22	0.34%	1.56%	0.01%	10.85%	0.04%
NiSource Inc	NI	448.305	29.06	13,027.74	0.04%	3.65%	0.00%	7.00%	0.00%
Norfolk Southern Corp	NSC	225.914	224.8	50,785.47	0.15%	2.40%	0.00%	8.84%	0.01%
Principal Financial Group Inc	PFG	234.384	81.33	19,062.45	0.06%	3.49%	0.00%	12.40%	0.01%
Eversource Energy	ES	350.727	59.23	20,773.56	0.06%	4.83%	0.00%	4.83%	0.00%
Northrop Grumman Corp	NOC	147.99	450.77	66,709.45	0.20%	1.83%	0.00%	18.34%	0.04%
Wells Fargo & Co	WFC	3486.315	59.92	208,899.99	0.62%	2.34%	0.01%	7.97%	0.05%
Nucor Corp	NUE	239.762	168.85	40,483.81		1.28%			
Occidental Petroleum Corp	OXY	886.637	62.5	55,414.81	0.17%	1.41%	0.00%	20.00%	0.03%
Omnicom Group Inc	OMC	195.834	92.96	18,204.73	0.05%	3.01%	0.00%	7.48%	0.00%
ONEOK Inc	OKE	583.647	81	47,275.41	0.14%	4.89%	0.01%	2.55%	0.00%
Raymond James Financial Inc	RJF	207.277	122.75	25,443.25	0.08%	1.47%	0.00%	15.38%	0.01%
PG&E Corp	PCG	2133.508	18.54	39,555.24	0.12%	0.22%	0.00%	10.10%	0.01%
Parker-Hannifin Corp	PH	128.541	531.52	68,322.11	0.20%	1.23%	0.00%	13.84%	0.03%
Rollins Inc	ROL	484.23	45.69	22,124.47	0.07%	1.31%	0.00%	13.04%	0.01%
PPL Corp	PPL	737.124	29.33	21,619.85	0.06%	3.51%	0.00%	7.34%	0.00%
ConocoPhillips	COP	1169.534	116.48	136,227.32	0.41%	2.68%	0.01%	9.00%	0.04%
PulteGroup Inc	PHM	210.342	117.32	24,677.32	0.07%	0.68%	0.00%	7.65%	0.01%
Pinnacle West Capital Corp	PNW	113.557	78.86	8,955.11	0.03%	4.46%	0.00%	7.61%	0.00%
PNC Financial Services Group Inc/The	PNC	397.907	157.39	62,626.58		3.94%		31.00%	
PPG Industries Inc	PPG	235.361	131.41	30,928.79	0.09%	1.98%	0.00%	8.03%	0.01%
Progressive Corp/The	PGR	585.698	211.18	123,687.70		0.19%		32.49%	
Veralto Corp	VLTO	246.847	98.58	24,334.18		0.37%			
Public Service Enterprise Group Inc	PEG	498.587	75.76	37,772.95	0.11%	3.17%	0.00%	5.99%	0.01%
Robert Half Inc	RHI	104.933	64.23	6,739.85	0.02%	3.30%	0.00%	4.20%	0.00%
Cooper Cos Inc/The	COO	199.12	94.31	18,779.01	0.06%			10.00%	0.01%
Edison International	EIX	383.925	76.85	29,504.64	0.09%	4.06%	0.00%	7.80%	0.01%
Schlumberger NV	SLB	1429.338	45.89	65,592.32	0.20%	2.40%	0.00%	14.81%	0.03%
Charles Schwab Corp/The	SCHW	1777.281	73.28	130,239.15	0.39%	1.36%	0.01%	14.20%	0.06%
Sherwin-Williams Co/The	SHW	253.549	303.8	77,028.19	0.23%	0.94%	0.00%	9.56%	0.02%
West Pharmaceutical Services Inc	WST	72.843	331.41	24,140.90	0.07%	0.24%	0.00%	7.72%	0.01%
J M Smucker Co/The	SJM	106.176	111.64	11,853.49	0.04%	3.80%	0.00%	7.04%	0.00%
Snap-on Inc	SNA	52.719	272.86	14,384.91	0.04%	2.73%	0.00%	3.83%	0.00%
AMETEK Inc	AME	231.47	169.58	39,252.68	0.12%	0.66%	0.00%	7.43%	0.01%
Uber Technologies Inc	UBER	2089.52	64.56	134,899.41				61.05%	
Southern Co/The	SO	1094.633	80.14	87,723.89	0.26%	3.59%	0.01%	7.10%	0.02%
Truist Financial Corp	TFC	1338.096	37.75	50,513.12	0.15%	5.51%	0.01%	10.51%	0.02%
Southwest Airlines Co	LUV	598.456	26.84	16,062.56		2.68%		21.33%	
W R Berkley Corp	WRB	255.662	81.03	20,716.29	0.06%	0.54%	0.00%	13.64%	0.01%
Stanley Black & Decker Inc	SWK	153.879	86.358	13,288.68	0.04%	3.75%	0.00%	7.00%	0.00%
Public Storage	PSA	175.829	273.83	48,147.26	0.14%	4.38%	0.01%	3.24%	0.00%
Arista Networks Inc	ANET	313.363	297.65	93,272.50	0.28%			12.42%	0.03%
Sysco Corp	SYY	497.982	72.82	36,263.05	0.11%	2.80%	0.00%	13.00%	0.01%
Corteva Inc	CTVA	687.797	55.7789	38,364.56	0.11%	1.15%	0.00%	11.33%	0.01%
Texas Instruments Inc	TXN	910.482	195.01	177,553.09		2.67%		-1.14%	
Textron Inc	TXT	190.699	87.61	16,707.14	0.05%	0.09%	0.00%	10.05%	0.01%
Thermo Fisher Scientific Inc	TMO	381.716	567.98	216,807.05	0.65%	0.27%	0.00%	7.40%	0.05%
TJX Cos Inc/The	TJX	1130.149	103.1	116,518.36	0.35%	1.45%	0.01%	8.13%	0.03%
Globe Life Inc	GL	92.27	82.76	7,636.27	0.02%	1.16%	0.00%	7.00%	0.00%
Johnson Controls International plc	JCI	673.676	71.91	48,444.04	0.14%	2.06%	0.00%	9.45%	0.01%
Ulta Beauty Inc	ULTA	47.716	395.09	18,852.11	0.06%			6.34%	0.00%
Union Pacific Corp	UNP	610.122	232.82	142,048.60	0.42%	2.23%	0.01%	12.88%	0.05%
Keysight Technologies Inc	KEYS	174.539	138.48	24,170.16				-1.09%	
UnitedHealth Group Inc	UNH	920.385	495.37	455,931.12	1.36%	1.52%	0.02%	10.38%	0.14%
Blackstone Inc	BX	714.646	120.5	86,114.84		2.76%		23.93%	
Marathon Oil Corp	MRO	564.036	28.96	16,334.48		1.52%			
Bio-Rad Laboratories Inc	BIO	23.446	286.86	6,725.72					
Ventas Inc	VTR	404.774	50.26	20,343.94	0.06%	3.58%	0.00%	6.19%	0.00%
Labcorp Holdings Inc	LH	84.294	194.91	16,429.74	0.05%	1.48%	0.00%	1.23%	0.00%
Vulcan Materials Co	VMC	132.252	255.77	33,826.09	0.10%	0.72%	0.00%	15.71%	0.02%
Weyerhaeuser Co	WY	729.617	30.03	21,910.40		2.66%		-0.33%	
Williams Cos Inc/The	WMB	1218.754	41.51	50,590.48	0.15%	4.58%	0.01%	3.94%	0.01%
Constellation Energy Corp	CEG	315.121	217.25	68,460.04	0.20%	0.65%	0.00%	11.80%	0.02%
WEC Energy Group Inc	WEC	315.823	81.03	25,591.14	0.08%	4.12%	0.00%	6.85%	0.01%
Adobe Inc	ADBE	448	444.76	199,252.48	0.59%			16.73%	0.10%
Vistra Corp	VST	347.46	99.08	34,426.34		0.88%			
AES Corp/The	AES	710.667	21.59	15,343.30		3.20%			
Expeditors International of Washington Inc	EXPD	141.252	120.17	16,974.25	0.05%	1.21%	0.00%	3.78%	0.00%
Amgen Inc	AMGN	536.435	305.85	164,068.64	0.49%	2.94%	0.01%	6.22%	0.03%
Apple Inc	AAPL	15334.082	192.25	2,947,977.26	8.78%	0.52%	0.05%	12.73%	1.12%
Autodesk Inc	ADSK	213.915	201.6	43,125.26	0.13%			12.76%	0.02%
Cintas Corp	CTAS	101.463	677.97	68,788.87	0.20%	0.80%	0.00%	12.04%	0.02%
Comcast Corp	CMCSA	3914.182	40.03	156,684.71	0.47%	3.10%	0.01%	8.33%	0.04%
Molson Coors Beverage Co	TAP	197.551	54.81	10,827.77	0.03%	3.21%	0.00%	4.65%	0.00%
KLA Corp	KLAC	134.64	759.53	102,263.12	0.30%	0.76%	0.00%	8.99%	0.03%
Marriott International Inc/MD	MAR	285.622	231.17	66,027.24	0.20%	1.09%	0.00%	5.56%	0.01%
Fiserv Inc	FI	585.102	149.76	87,624.88	0.26%			15.47%	0.04%
McCormick & Co Inc/MD	MKC	251.745	72.22	18,181.02	0.05%	2.33%	0.00%	5.96%	0.00%
PACCAR Inc	PCAR	524.145	107.5	56,345.59		1.12%		-2.16%	
Costco Wholesale Corp	COST	443.504	809.89	359,189.45	1.07%	0.57%	0.01%	9.64%	0.10%
Stryker Corp	SYK	380.95	341.09	129,938.24	0.39%	0.94%	0.00%	8.39%	0.03%

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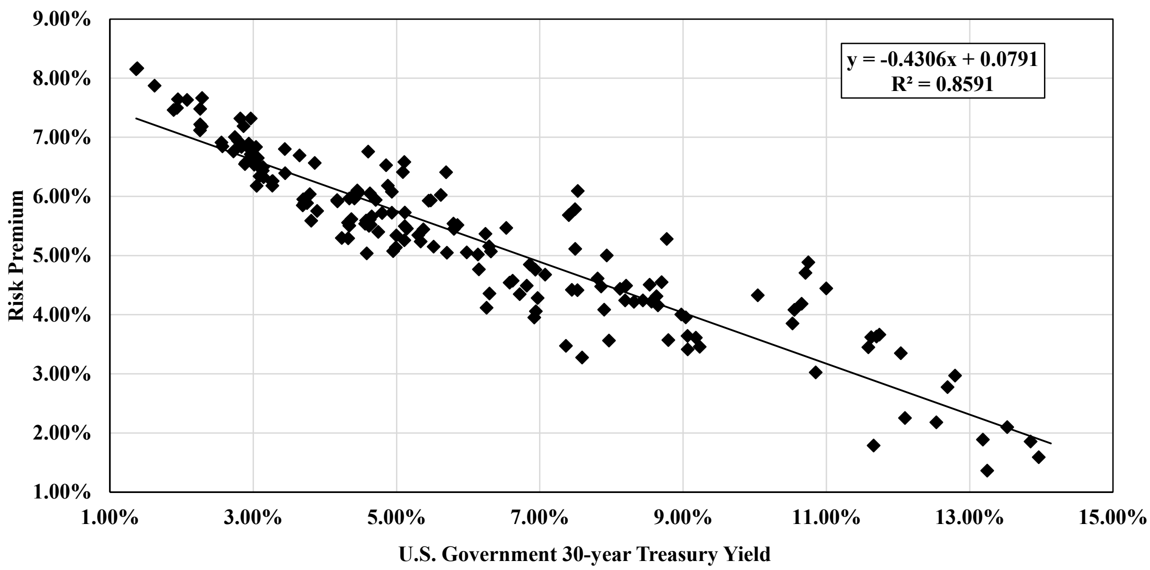
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Tyson Foods Inc	TSN	286.016	57.25	16,374.42		3.42%		53.92%	
Lamb Weston Holdings Inc	LW	144.391	88.29	12,748.28	0.04%	1.63%	0.00%	11.56%	0.00%
Applied Materials Inc	AMAT	827.975	215.08	178,080.86	0.53%	0.74%	0.00%	15.06%	0.08%
American Airlines Group Inc	AAL	653.541	11.5	7,515.72				-4.75%	
Cardinal Health Inc	CAH	243.567	99.27	24,178.90	0.07%	2.04%	0.00%	13.47%	0.01%
Cincinnati Financial Corp	CINF	156.558	117.58	18,408.09	0.05%	2.76%	0.00%	7.35%	0.00%
Paramount Global	PARA	625.776	11.91	7,452.99		1.68%		48.12%	
DR Horton Inc	DHI	329.312	147.8	48,672.31	0.14%	0.81%	0.00%	4.37%	0.01%
Electronic Arts Inc	EA	266.379	132.88	35,396.44	0.11%	0.57%	0.00%	12.24%	0.01%
Fair Isaac Corp	FICO	24.711	1289.93	31,875.46					
Fastenal Co	FAST	572.427	65.98	37,768.73		2.36%			
M&T Bank Corp	MTB	166.854	150.25	25,069.81	0.07%	3.59%	0.00%	5.82%	0.00%
Xcel Energy Inc	XEL	555.639	55.45	30,810.18	0.09%	3.95%	0.00%	6.70%	0.01%
Fifth Third Bancorp	FITB	684.045	37.42	25,596.96		3.74%		25.00%	
Gilead Sciences Inc	GILD	1245.853	64.27	80,070.97	0.24%	4.79%	0.01%	14.38%	0.03%
Hasbro Inc	HAS	139.216	59.78	8,322.33	0.02%	4.68%	0.00%	17.10%	0.00%
Huntington Bancshares Inc/OH	HBAN	1449.254	13.92	20,173.62	0.06%	4.45%	0.00%	4.46%	0.00%
Welltower Inc	WELL	597.916	103.67	61,985.95	0.18%	2.35%	0.00%	14.68%	0.03%
Biogen Inc	BIIB	145.597	224.94	32,750.59	0.10%			5.36%	0.01%
Northern Trust Corp	NTRS	204.592	84.24	17,234.83	0.05%	3.56%	0.00%	10.80%	0.01%
Packaging Corp of America	PKG	89.798	183.49	16,477.04	0.05%	2.72%	0.00%	2.83%	0.00%
Paychex Inc	PAYX	359.963	120.16	43,253.15	0.13%	3.26%	0.00%	6.17%	0.01%
QUALCOMM Inc	QCOM	1116	204.05	227,719.80	0.68%	1.67%	0.01%	11.88%	0.08%
Ross Stores Inc	ROST	335.174	139.76	46,843.92		1.05%		188.00%	
IDEXX Laboratories Inc	IDXX	82.587	496.95	41,041.61	0.12%			11.11%	0.01%
Starbucks Corp	SBUX	1132.2	80.22	90,825.08	0.27%	2.84%	0.01%	12.42%	0.03%
KeyCorp	KEY	942.86	14.37	13,548.90	0.04%	5.71%	0.00%	19.11%	0.01%
Fox Corp	FOXA	231.15	34.43	7,958.49	0.02%	1.51%	0.00%	6.61%	0.00%
Fox Corp	FOX	235.581	31.94	7,524.46	0.02%	1.63%	0.00%	6.61%	0.00%
State Street Corp	STT	301.259	75.59	22,772.17	0.07%	3.65%	0.00%	8.07%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	429.041	16.6	7,122.08				51.83%	
US Bancorp	USB	1560.46	40.55	63,276.65	0.19%	4.83%	0.01%	2.71%	0.01%
A O Smith Corp	AOS	120.784	83.64	10,102.37		1.53%			
Gen Digital Inc	GEN	626.146	24.83	15,547.21	0.05%	2.01%	0.00%	10.16%	0.00%
T Rowe Price Group Inc	TROW	223.3	117.83	26,311.44	0.08%	4.21%	0.00%	5.88%	0.00%
Waste Management Inc	WM	401.083	210.73	84,520.22	0.25%	1.42%	0.00%	11.11%	0.03%
Constellation Brands Inc	STZ	182.953	250.23	45,780.33	0.14%	1.61%	0.00%	11.21%	0.02%
Invesco Ltd	IVZ	449.831	15.71	7,066.85	0.02%	5.22%	0.00%	8.71%	0.00%
Intuit Inc	INTU	279.547	576.44	161,142.07	0.48%	0.62%	0.00%	15.15%	0.07%
Morgan Stanley	MS	1625.163	97.84	159,005.95	0.47%	3.48%	0.02%	9.49%	0.04%
Microchip Technology Inc	MCHP	536.886	97.23	52,201.43		1.86%		-9.39%	
Chubb Ltd	CB	406.061	270.82	109,969.44	0.33%	1.34%	0.00%	2.45%	0.01%
Hologic Inc	HOLX	233.377	73.78	17,218.56	0.05%			7.36%	0.00%
Citizens Financial Group Inc	CFG	455.02	35.29	16,057.66		4.76%			
Jabil Inc	JBL	120.597	118.9	14,338.98	0.04%	0.27%	0.00%	10.30%	0.00%
O'Reilly Automotive Inc	ORLY	58.894	963.26	56,730.23	0.17%			11.00%	0.02%
Allstate Corp/The	ALL	263.915	167.52	44,211.04		2.20%		175.32%	
Equity Residential	EQR	378.94	65.03	24,642.47	0.07%	4.15%	0.00%	3.98%	0.00%
BorgWarner Inc	BWA	227.838	35.55	8,099.64	0.02%	1.24%	0.00%	4.17%	0.00%
Keurig Dr Pepper Inc	KDP	1355.574	34.25	46,428.41	0.14%	2.51%	0.00%	7.12%	0.01%
Host Hotels & Resorts Inc	HST	703.6	17.94	12,622.58		4.46%		-0.49%	
Incyte Corp	INCY	224.855	57.79	12,994.37	0.04%			19.22%	0.01%
Simon Property Group Inc	SPG	325.766	151.31	49,291.65	0.15%	5.29%	0.01%	1.31%	0.00%
Eastman Chemical Co	EMN	117.649	101.33	11,921.37	0.04%	3.20%	0.00%	6.19%	0.00%
AvalonBay Communities Inc	AVB	142.186	192.68	27,396.40	0.08%	3.53%	0.00%	7.71%	0.01%
Prudential Financial Inc	PRU	359	120.35	43,205.65	0.13%	4.32%	0.01%	9.96%	0.01%
United Parcel Service Inc	UPS	729.399	138.93	101,335.40	0.30%	4.69%	0.01%	8.77%	0.03%
Walgreens Boots Alliance Inc	WBA	862.713	16.22	13,993.20		6.17%		-4.38%	
STERIS PLC	STE	98.9	222.88	22,042.83		0.93%			
McKesson Corp	MCK	129.986	568.97	73,958.13	0.22%	0.44%	0.00%	11.67%	0.03%
Lockheed Martin Corp	LMT	239.938	467.19	112,096.63	0.33%	2.70%	0.01%	2.21%	0.01%
Cencora Inc	COR	196.929	226.57	44,618.20	0.13%	0.90%	0.00%	10.82%	0.01%
Capital One Financial Corp	COF	381.922	137.63	52,563.92	0.16%	1.74%	0.00%	12.55%	0.02%
Waters Corp	WAT	59.32	308.9	18,323.95	0.05%			5.12%	0.00%
Nordson Corp	NDSN	57.269	234.72	13,442.18		1.16%			
Dollar Tree Inc	DLTR	217.983	117.95	25,711.09	0.08%			14.10%	0.01%
Darden Restaurants Inc	DRI	119.359	150.39	17,950.40	0.05%	3.48%	0.00%	10.89%	0.01%
Evergy Inc	EVRG	229.746	54.66	12,557.92	0.04%	4.70%	0.00%	5.00%	0.00%
Match Group Inc	MTCH	265.668	30.63	8,137.41				35.69%	
Domino's Pizza Inc	DPZ	34.88	508.58	17,739.27	0.05%	1.19%	0.00%	14.43%	0.01%
NVR Inc	NVR	3.132	7680.73	24,056.05	0.07%			4.87%	0.00%
NetApp Inc	NTAP	206.377	120.43	24,853.98		1.73%			
Old Dominion Freight Line Inc	ODFL	217.285	175.25	38,079.20	0.11%	0.59%	0.00%	13.12%	0.01%
DaVita Inc	DVA	87.7	147.12	12,902.42	0.04%			15.98%	0.01%
Hartford Financial Services Group Inc/The	HIG	295.755	102.98	30,456.85	0.09%	1.83%	0.00%	12.22%	0.01%
Iron Mountain Inc	IRM	293.133	80.69	23,652.90	0.07%	3.22%	0.00%	4.00%	0.00%
Estee Lauder Cos Inc/The	EL	233.022	123.36	28,745.59	0.09%	2.14%	0.00%	16.13%	0.01%
Cadence Design Systems Inc	CDNS	272.134	286.31	77,914.69	0.23%			15.67%	0.04%
Tyler Technologies Inc	TYL	42.455	480.36	20,393.68					
Universal Health Services Inc	UHS	59.678	189.6	11,314.95	0.03%	0.42%	0.00%	17.84%	0.01%
Skyworks Solutions Inc	SWKS	160.447	92.66	14,867.02		2.94%		-1.59%	
Quest Diagnostics Inc	DGX	111.092	141.97	15,771.73		2.11%		-0.82%	
Rockwell Automation Inc	ROK	114.003	257.53	29,359.19	0.09%	1.94%	0.00%	5.23%	0.00%
Kraft Heinz Co/The	KHC	1214.298	35.37	42,949.72	0.13%	4.52%	0.01%	3.77%	0.00%
American Tower Corp	AMT	466.975	195.74	91,405.69	0.27%	3.31%	0.01%	11.49%	0.03%
Regeneron Pharmaceuticals Inc	REGN	108.367	980.16	106,217.00	0.32%			6.96%	0.02%
Amazon.com Inc	AMZN	10406.627	176.44	1,836,145.27				28.96%	
Jack Henry & Associates Inc	JKHY	72.9	164.68	12,005.17	0.04%	1.34%	0.00%	7.46%	0.00%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Ralph Lauren Corp	RL	40.628	186.88	7,592.56	0.02%	1.77%	0.00%	11.05%	0.00%
Boston Properties Inc	BXP	157.049	60.67	9,528.16	0.03%	6.46%	0.00%	0.21%	0.00%
Amphenol Corp	APH	600.604	132.37	79,501.95	0.24%	0.33%	0.00%	13.49%	0.03%
Howmet Aerospace Inc	HWM	408.183	84.65	34,552.69	0.10%	0.24%	0.00%	19.82%	0.02%
Valero Energy Corp	VLO	326.996	157.14	51,384.15		2.72%		-24.00%	
Synopsys Inc	SNPS	153.216	560.8	85,923.53	0.26%			16.59%	0.04%
Etsy Inc	ETSY	116.933	63.47	7,421.74	0.02%			7.51%	0.00%
CH Robinson Worldwide Inc	CHRW	117.095	86.37	10,113.50	0.03%	2.83%	0.00%	11.80%	0.00%
Accenture PLC	ACN	670.422	282.29	189,253.43	0.56%	1.83%	0.01%	6.68%	0.04%
TransDigm Group Inc	TDG	55.958	1343.23	75,164.46	0.22%			18.82%	0.04%
Yum! Brands Inc	YUM	281.632	137.43	38,704.69	0.12%	1.95%	0.00%	10.66%	0.01%
Prologis Inc	PLD	925.844	110.49	102,296.50	0.30%	3.48%	0.01%	7.57%	0.02%
FirstEnergy Corp	FE	575.516	40.26	23,170.27	0.07%	4.22%	0.00%	6.65%	0.00%
VeriSign Inc	VRSN	100.139	174.32	17,456.23					
Quanta Services Inc	PWR	146.388	275.94	40,394.30	0.12%	0.13%	0.00%	12.00%	0.01%
Henry Schein Inc	HSIC	128.051	69.34	8,879.06	0.03%			7.53%	0.00%
Ameren Corp	AEE	266.511	73.37	19,553.91	0.06%	3.65%	0.00%	6.00%	0.00%
ANSYS Inc	ANSS	87.3	317.45	27,713.39	0.08%			6.37%	0.01%
FactSet Research Systems Inc	FDS	38.116	404.26	15,408.77	0.05%	1.03%	0.00%	9.42%	0.00%
NVIDIA Corp	NVDA	2460	1096.33	2,696,971.80		0.00%		35.80%	
Cognizant Technology Solutions Corp	CTSH	497.199	66.15	32,889.71	0.10%	1.81%	0.00%	5.15%	0.01%
Intuitive Surgical Inc	ISRG	354.706	402.12	142,634.38	0.42%			16.21%	0.07%
Take-Two Interactive Software Inc	TTWO	171.385	160.36	27,483.30					
Republic Services Inc	RSG	314.975	185.19	58,330.22	0.17%	1.16%	0.00%	10.52%	0.02%
eBay Inc	EBAY	506	54.22	27,435.32	0.08%	1.99%	0.00%	7.83%	0.01%
Goldman Sachs Group Inc/The	GS	322.463	456.52	147,210.81	0.44%	2.41%	0.01%	14.02%	0.06%
SBA Communications Corp	SBAC	107.443	196.68	21,131.89		1.99%		23.41%	
Sempra	SRE	632.846	77.03	48,748.13	0.15%	3.22%	0.00%	3.85%	0.01%
Moody's Corp	MCO	182.6	396.99	72,490.37	0.22%	0.86%	0.00%	11.79%	0.03%
ON Semiconductor Corp	ON	430.232	73.04	31,424.15	0.09%			2.64%	0.00%
Booking Holdings Inc	BKNG	33.928	3776.35	128,124.00	0.38%	0.93%	0.00%	15.03%	0.06%
F5 Inc	FFIV	58.611	168.97	9,903.50	0.03%			7.81%	0.00%
Akamai Technologies Inc	AKAM	152.317	92.24	14,049.72	0.04%			1.54%	0.00%
Charles River Laboratories International Inc	CRL	51.512	208.44	10,737.16	0.03%			9.81%	0.00%
MarketAxess Holdings Inc	MKTX	37.897	198.93	7,538.85	0.02%	1.49%	0.00%	3.07%	0.00%
Devon Energy Corp	DVN	632	49.08	31,018.56		2.85%			
Bio-Techne Corp	TECH	157.585	77.19	12,163.99		0.41%			
Alphabet Inc	GOOGL	5874	172.5	1,013,265.00	3.02%	0.46%	0.01%	15.01%	0.45%
Teleflex Inc	TFX	47.103	209.07	9,847.82	0.03%	0.65%	0.00%	7.51%	0.00%
Netflix Inc	NFLX	430.965	641.62	276,515.76				35.61%	
Allegion plc	ALLE	87.441	121.82	10,652.06	0.03%	1.58%	0.00%	7.25%	0.00%
Agilent Technologies Inc	A	293.055	130.41	38,217.30	0.11%	0.72%	0.00%	5.23%	0.01%
Warner Bros Discovery Inc	WBD	2450.313	8.24	20,190.58				34.78%	
Elevance Health Inc	ELV	232.418	538.48	125,152.44	0.37%	1.21%	0.00%	12.03%	0.04%
Trimble Inc	TRMB	244.208	55.68	13,597.50	0.04%			10.00%	0.00%
CME Group Inc	CME	360.062	202.98	73,085.38	0.22%	2.27%	0.00%	4.90%	0.01%
Juniper Networks Inc	JNPR	324.988	35.45	11,520.82	0.03%	2.48%	0.00%	4.78%	0.00%
BlackRock Inc	BLK	148.6	772.03	114,723.66	0.34%	2.64%	0.01%	11.89%	0.04%
DTE Energy Co	DTE	206.925	116.53	24,112.97	0.07%	3.50%	0.00%	8.70%	0.01%
Nasdaq Inc	NDAQ	576.533	59.03	34,032.74	0.10%	1.63%	0.00%	5.72%	0.01%
Celanese Corp	CE	109.22	152.04	16,605.81		1.84%		22.38%	
Philip Morris International Inc	PM	1554.557	101.38	157,600.99	0.47%	5.13%	0.02%	8.23%	0.04%
Salesforce Inc	CRM	969	234.44	227,172.36	0.68%	0.68%	0.00%	17.34%	0.12%
Ingersoll Rand Inc	IR	403.432	93.05	37,539.35	0.11%	0.09%	0.00%	16.00%	0.02%
Huntington Ingalls Industries Inc	HII	39.433	253.1	9,980.49	0.03%	2.05%	0.00%	7.78%	0.00%
Roper Technologies Inc	ROP	107.045	532.76	57,029.29		0.56%			
MetLife Inc	MET	711.123	72.37	51,463.97	0.15%	3.01%	0.00%	13.85%	0.02%
Tapestry Inc	TPR	229.773	43.49	9,992.83	0.03%	3.22%	0.00%	9.91%	0.00%
CSX Corp	CSX	1954.927	33.75	65,978.79	0.20%	1.42%	0.00%	10.76%	0.02%
Edwards Lifesciences Corp	EW	601.3	86.89	52,246.96	0.16%			10.03%	0.02%
Ameriprise Financial Inc	AMP	99.325	436.61	43,366.29		1.36%			
Zebra Technologies Corp	ZBRA	51.419	312.34	16,060.21					
Zimmer Biomet Holdings Inc	ZBH	205.728	115.15	23,689.58	0.07%	0.83%	0.00%	7.00%	0.00%
CBRE Group Inc	CBRE	306.824	88.07	27,021.99					
Camden Property Trust	CPT	106.535	102.65	10,935.82	0.03%	4.01%	0.00%	1.59%	0.00%
Mastercard Inc	MA	922.47	447.07	412,408.66	1.23%	0.59%	0.01%	15.54%	0.19%
CarMax Inc	KMX	157.327	70.26	11,053.80	0.03%			18.69%	0.01%
Intercontinental Exchange Inc	ICE	573.585	133.9	76,803.03	0.23%	1.34%	0.00%	8.96%	0.02%
Fidelity National Information Services Inc	FIS	556.251	75.88	42,208.33		1.90%		21.47%	
Chipotle Mexican Grill Inc	CMG	27.467	3129.52	85,958.53				22.95%	
Wynn Resorts Ltd	WYNN	112.071	94.88	10,633.30		1.05%		-4.07%	
Live Nation Entertainment Inc	LYV	231.443	93.74	21,695.47					
Assurant Inc	AIZ	51.986	173.47	9,018.01	0.03%	1.66%	0.00%	6.19%	0.00%
NRG Energy Inc	NRG	208.476	81	16,886.56	0.05%	2.01%	0.00%	3.00%	0.00%
Regions Financial Corp	RF	915.827	19.11	17,501.45	0.05%	5.02%	0.00%	4.18%	0.00%
Monster Beverage Corp	MNST	1041.728	51.92	54,086.52	0.16%			12.72%	0.02%
Mosaic Co/The	MOS	321.393	30.93	9,940.69		2.72%		-18.32%	
Baker Hughes Co	BKR	997.998	33.48	33,412.97		2.51%		27.93%	
Expedia Group Inc	EXPE	127.224	112.86	14,358.50				22.40%	
CF Industries Holdings Inc	CF	182.782	79.73	14,573.21		2.51%		-4.63%	
Leidos Holdings Inc	LDOS	135.212	147.05	19,882.92	0.06%	1.03%	0.00%	10.53%	0.01%
APA Corp	APA	371.192	30.53	11,332.49		3.28%			
Alphabet Inc	GOOG	5617	173.96	977,133.32	2.91%	0.46%	0.01%	15.01%	0.44%
First Solar Inc	FSLR	107.041	271.76	29,089.46				29.00%	
TE Connectivity Ltd	TEL	306.228	149.7	45,842.33	0.14%	1.74%	0.00%	5.04%	0.01%
Discover Financial Services	DFS	250.599	122.66	30,738.47		2.28%		61.19%	
Visa Inc	V	1574.152	272.46	428,893.45	1.28%	0.76%	0.01%	13.05%	0.17%
Mid-America Apartment Communities Inc	MAA	116.688	133.71	15,602.35	0.05%	4.40%	0.00%	0.83%	0.00%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Xylem Inc/NY	XYL	242.447	141.02	34,189.88		1.02%			
Marathon Petroleum Corp	MPC	352.33	176.61	62,225.00		1.87%			
Advanced Micro Devices Inc	AMD	1616.314	166.9	269,762.81				31.82%	
Tractor Supply Co	TSCO	107.81	285.29	30,757.11	0.09%	1.54%	0.00%	5.15%	0.00%
ResMed Inc	RMD	146.907	206.33	30,311.32	0.09%	0.93%	0.00%	13.45%	0.01%
Mettler-Toledo International Inc	MTD	21.357	1404.09	29,987.15	0.09%			9.29%	0.01%
Jacobs Solutions Inc	J	125.213	139.34	17,447.18	0.05%	0.83%	0.00%	10.76%	0.01%
Copart Inc	CPRT	962.298	53.06	51,059.53					
VICI Properties Inc	VICI	1043.137	28.71	29,948.46	0.09%	5.78%	0.01%	5.44%	0.00%
Fortinet Inc	FTNT	763.938	59.32	45,316.80	0.13%			9.59%	0.01%
Albemarle Corp	ALB	117.527	122.59	14,407.63		1.31%		-12.70%	
Moderna Inc	MRNA	383.24	142.55	54,630.86	0.16%			17.59%	0.03%
Essex Property Trust Inc	ESS	64.206	259.79	16,680.08	0.05%	3.77%	0.00%	4.64%	0.00%
CoStar Group Inc	CSGP	408.342	78.17	31,920.09	0.10%			15.09%	0.01%
Realty Income Corp	O	870.774	52.7975	45,974.69	0.14%	5.97%	0.01%	5.24%	0.01%
Westrock Co	WRK	258.148	53.64	13,847.06	0.04%	2.26%	0.00%	7.48%	0.00%
Westinghouse Air Brake Technologies Corp	WAB	176.385	169.23	29,849.63	0.09%	0.47%	0.00%	15.49%	0.01%
Pool Corp	POOL	38.329	363.55	13,934.51	0.04%	1.32%	0.00%	4.73%	0.00%
Western Digital Corp	WDC	326.525	75.29	24,584.07				-10.00%	
PepsiCo Inc	PEP	1374.786	172.9	237,700.50	0.71%	3.13%	0.02%	7.91%	0.06%
Diamondback Energy Inc	FANG	178.344	199.26	35,536.83		3.95%			
Palo Alto Networks Inc	PANW	323.8	294.91	95,491.86	0.28%			11.00%	0.03%
ServiceNow Inc	NOW	205	656.93	134,670.65				25.00%	
Church & Dwight Co Inc	CHD	244.523	107.01	26,166.41	0.08%	1.06%	0.00%	11.04%	0.01%
Federal Realty Investment Trust	FRT	82.775	100.95	8,356.14	0.02%	4.32%	0.00%	4.11%	0.00%
MGM Resorts International	MGM	313.68	40.17	12,600.53	0.04%			15.86%	0.01%
American Electric Power Co Inc	AEP	526.59	90.25	47,524.75	0.14%	3.90%	0.01%	6.10%	0.01%
Invitation Homes Inc	INVH	612.536	34.79	21,310.13	0.06%	3.22%	0.00%	5.86%	0.00%
PTC Inc	PTC	119.744	176.24	21,103.68	0.06%			14.94%	0.01%
JB Hunt Transport Services Inc	JBHT	103.197	160.75	16,588.92	0.05%	1.07%	0.00%	13.58%	0.01%
Lam Research Corp	LRCX	130.736	932.44	121,903.48	0.36%	0.86%	0.00%	8.61%	0.03%
Mohawk Industries Inc	MHK	63.863	121.93	7,786.82	0.02%			2.74%	0.00%
Pentair PLC	PNR	166.025	81.38	13,511.11	0.04%	1.13%	0.00%	13.13%	0.01%
GE HealthCare Technologies Inc	GEHC	456.465	78	35,604.27	0.11%	0.15%	0.00%	11.26%	0.01%
Vertex Pharmaceuticals Inc	VRTX	258.053	455.34	117,501.85	0.35%			12.79%	0.04%
Amcor PLC	AMCR	1445.343	10.17	14,699.14	0.04%	4.92%	0.00%	2.63%	0.00%
Meta Platforms Inc	META	2191.446	466.83	1,023,032.74	3.05%	0.43%	0.01%	18.58%	0.57%
T-Mobile US Inc	TMUS	1171.854	174.96	205,027.58	0.61%	1.49%	0.01%	5.00%	0.03%
United Rentals Inc	URI	66.59	669.41	44,576.01	0.13%	0.97%	0.00%	5.27%	0.01%
Honeywell International Inc	HON	651.186	202.19	131,663.30	0.39%	2.14%	0.01%	8.50%	0.03%
Alexandria Real Estate Equities Inc	ARE	174.883	119	20,811.08	0.06%	4.27%	0.00%	4.21%	0.00%
Delta Air Lines Inc	DAL	645.312	51.02	32,923.82	0.10%	0.78%	0.00%	12.00%	0.01%
Seagate Technology Holdings PLC	STX	209.989	93.24	19,579.37		3.00%			
United Airlines Holdings Inc	UAL	328.803	52.99	17,423.27	0.05%			12.79%	0.01%
News Corp	NWS	190.684	27.88	5,316.27		0.72%			
Centene Corp	CNC	534.906	71.59	38,293.92	0.11%			5.16%	0.01%
Martin Marietta Materials Inc	MLM	61.64	571.34	35,217.40	0.10%	0.52%	0.00%	9.71%	0.01%
Teradyne Inc	TER	156.112	140.94	22,002.43	0.07%	0.34%	0.00%	17.47%	0.01%
PayPal Holdings Inc	PYPL	1046.046	62.99	65,890.44	0.20%			8.69%	0.02%
Tesla Inc	TSLA	3189.196	178.08	567,932.02					
Arch Capital Group Ltd	ACGL	375.494	102.63	38,536.95	0.11%			3.53%	0.00%
Dow Inc	DOW	703.268	57.63	40,529.33	0.12%	4.86%	0.01%	2.46%	0.00%
Everest Group Ltd	EG	43.458	390.93	16,989.04	0.05%	2.05%	0.00%	1.85%	0.00%
Teledyne Technologies Inc	TDY	47.422	396.95	18,824.16	0.06%			7.34%	0.00%
GE Vernova Inc	GEV	274.086	175.9	48,211.73				63.97%	
News Corp	NWSA	379.205	27.19	10,310.58		0.74%			
Exelon Corp	EXC	999.735	37.55	37,540.05	0.11%	4.05%	0.00%	5.27%	0.01%
Global Payments Inc	GPN	255.25	101.85	25,997.21	0.08%	0.98%	0.00%	11.80%	0.01%
Crown Castle Inc	CCI	434.523	102.5	44,538.61		6.11%		-8.74%	
Aptiv PLC	APTV	272.062	83.26	22,651.88				24.81%	
Align Technology Inc	ALGN	75.282	257.21	19,363.28	0.06%			11.74%	0.01%
Illumina Inc	ILMN	159.3	104.28	16,611.80				40.05%	
Kenvue Inc	KVUE	1914.811	19.3	36,955.85	0.11%	4.15%	0.00%	15.93%	0.02%
Targa Resources Corp	TRGP	221.717	118.23	26,213.60		2.54%		21.12%	
Bunge Global SA	BG	141.595	107.59	15,234.21		2.53%		-8.30%	
Deckers Outdoor Corp	DECK	25.442	1093.92	27,831.51	0.08%			8.39%	0.01%
LKQ Corp	LKQ	266.776	43.03	11,479.37		2.79%			
Zoetis Inc	ZTS	456.295	169.56	77,369.38	0.23%	1.02%	0.00%	10.36%	0.02%
Digital Realty Trust Inc	DLR	324.502	145.34	47,163.12		3.36%		-15.66%	
Equinix Inc	EQIX	94.906	762.98	72,411.38	0.22%	2.23%	0.00%	10.10%	0.02%
Las Vegas Sands Corp	LVS	745.047	45.03	33,549.47		1.78%			
Molina Healthcare Inc	MOH	59	314.58	18,560.22	0.06%			11.72%	0.01%

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of May 31, 2024
[5] Bloomberg Professional as of May 31, 2024
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of May 31, 2024
[9] Equals [7] x [8]
[10] Value Line, as of May 31, 2024
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9268908
R Square	0.8591265
Adjusted R Square	0.8583075
Standard Error	0.0054049
Observations	174

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03064	0.03064	1,048.95352	0.00000
Residual	172	0.00502	0.00003		
Total	173	0.03567			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0791	0.00	87.45	0.0000	0.0773	0.0808	0.0773	0.0808
U.S. Govt. 30-year Treasury	(0.4306)	0.01	(32.39)	0.0000	(0.4568)	(0.4043)	(0.4568)	(0.4043)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.66%	5.90%	10.56%
Blue Chip Near-Term Projected Forecast (Q3 2024 - Q3 2025) [5]	4.40%	6.01%	10.41%
Blue Chip Long-Term Projected Forecast (2026-2030) [6]	4.30%	6.05%	10.35%
AVERAGE			10.44%

Notes:
[1] Regulatory Research Associates, rate cases through May 31, 2024
[2] S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] S&P Capital IQ Pro, 30-day average as of May 31, 2024
[5] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 2
[6] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.079056 + (-0.430580 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.45%	11.66%	1.79%
1980.2	14.38%	10.52%	3.85%
1980.3	13.87%	10.85%	3.02%
1980.4	14.35%	12.10%	2.25%
1981.1	14.71%	12.53%	2.18%
1981.2	14.61%	13.24%	1.36%
1981.3	14.86%	14.13%	0.72%
1981.4	15.70%	13.85%	1.86%
1982.1	15.55%	13.96%	1.59%
1982.2	15.62%	13.52%	2.10%
1982.3	15.77%	12.79%	2.97%
1982.4	15.63%	10.75%	4.89%
1983.1	15.41%	10.71%	4.71%
1983.2	14.84%	10.65%	4.19%
1983.3	15.24%	11.62%	3.62%
1983.4	15.40%	11.74%	3.66%
1984.1	15.39%	12.04%	3.35%
1984.2	15.07%	13.18%	1.89%
1984.3	15.46%	12.69%	2.77%
1984.4	15.33%	11.70%	3.63%
1985.1	15.03%	11.58%	3.45%
1985.2	15.44%	11.00%	4.45%
1985.3	14.64%	10.55%	4.08%
1985.4	14.37%	10.04%	4.33%
1986.1	14.05%	8.77%	5.28%
1986.2	13.28%	7.49%	5.79%
1986.3	13.09%	7.40%	5.69%
1986.4	13.62%	7.53%	6.09%
1987.1	12.61%	7.49%	5.11%
1987.2	13.04%	8.53%	4.51%
1987.3	12.70%	9.06%	3.64%
1987.4	12.69%	9.23%	3.46%
1988.1	12.94%	8.63%	4.31%
1988.2	12.48%	9.06%	3.41%
1988.3	12.79%	9.18%	3.61%
1988.4	12.98%	8.97%	4.00%
1989.1	12.99%	9.04%	3.96%
1989.2	13.25%	8.70%	4.55%
1989.3	12.56%	8.12%	4.44%
1989.4	12.94%	7.93%	5.00%
1990.1	12.68%	8.44%	4.24%
1990.2	12.81%	8.65%	4.16%
1990.3	12.36%	8.79%	3.57%
1990.4	12.78%	8.56%	4.22%
1991.1	12.69%	8.20%	4.49%
1991.2	12.53%	8.31%	4.22%
1991.3	12.43%	8.19%	4.24%
1991.4	12.33%	7.85%	4.48%
1992.1	12.42%	7.81%	4.61%
1992.2	11.98%	7.90%	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%	6.32%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.58%	4.54%
1994.2	10.84%	7.36%	3.47%
1994.3	10.87%	7.59%	3.28%

Quarter	[1] Average Authorized Natual Gas ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1994.4	11.53%	7.96%	3.56%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.72%	4.35%
1995.4	11.61%	6.24%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	6.97%	4.28%
1996.4	11.19%	6.62%	4.57%
1997.1	11.31%	6.82%	4.49%
1997.2	11.70%	6.94%	4.76%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.15%	4.77%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.48%	5.93%
1998.4	11.69%	5.11%	6.58%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.80%	5.45%
1999.4	10.38%	6.26%	4.12%
2000.1	10.66%	6.30%	4.36%
2000.2	11.03%	5.98%	5.05%
2000.3	11.33%	5.79%	5.54%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.45%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.52%	5.15%
2002.2	11.64%	5.62%	6.03%
2002.3	11.50%	5.09%	6.41%
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%	5.34%	5.24%
2004.3	10.37%	5.11%	5.26%
2004.4	10.66%	4.93%	5.73%
2005.1	10.65%	4.71%	5.94%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.42%	6.05%
2005.4	10.32%	4.65%	5.66%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	5.00%	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%
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%	5.59%
2008.3	10.55%	4.45%	6.10%
2008.4	10.34%	3.64%	6.69%
2009.1	10.24%	3.44%	6.80%
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%	4.37%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.92%

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.70%	5.95%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.94%	6.89%
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%	3.27%	6.18%
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%	6.71%
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%	3.05%	6.55%
2017.2	9.47%	2.90%	6.57%
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%	7.67%
2019.4	9.74%	2.26%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.87%
2021.1	9.71%	2.07%	7.63%
2021.2	9.48%	2.26%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.95%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.05%	6.18%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.89%	5.75%
2023.1	9.64%	3.75%	5.89%
2023.2	9.40%	3.81%	5.59%
2023.3	9.53%	4.23%	5.30%
2023.4	9.62%	4.58%	5.04%
2024.1	9.62%	4.32%	5.29%
2024.2	10.16%	4.64%	5.52%
AVERAGE	11.36%	6.06%	5.30%
MEDIAN	10.78%	5.13%	5.50%

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization

Company	Ticker	[1] Market Capitalization ($ billions)
Atmos Energy Corporation	ATO	17.69
NiSource Inc.	NI	12.76
Northwest Natural Gas Company	NWN	1.44
ONE Gas Inc.	OGS	3.59
Spire, Inc.	SR	3.55
Median		3.59

Montana-Dakota Utilities Co.			
Test Year Rate Base ($millions)	[2]	$	123.05
Company-Projected Common Equity Ratio	[3]		50.16%
Common Equity ($millions)	[4]	$	61.72
Market Capitalization of Proxy Group (median) ($millions)	[5]	$	3,592.68

Kroll Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10			[6] Market Capitalization of Largest Company ($ millions)	[7] Size Premium
1-Largest			2,662,326.05	-0.26%
2			36,391.11	0.45%
3			14,820.05	0.57%
4			7,461.28	0.58%
5			4,621.79	0.93%
6			3,010.81	1.16%
7			1,862.49	1.37%
8			1,046.04	1.18%
9			554.52	2.15%
10-Smallest			212.64	4.83%
Montana-Dakota Utilities Co. Common Equity	[4]	$	61.72	4.83%
Proxy Group Market Capitalization (median)	[5]	$	3,592.68	0.93%
Size Premium	[8]			3.90%

Notes:
[1] S&P Capital IQ Pro, equals 30-day average as of May 31, 2024
[2] Data provided by the Company
[3] Data provided by the Company
[4] Equals [2] x [3]
[5] Equals median market capitalization of proxy group x 1000
[6]-[7] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2023
[8] Size Premium of Montana-Dakota Utilities Co. less Size Premium of Proxy Group

FLOTATION COST ADJUSTMENT

Company	Ticker	Date [i]	[1] Shares Issued (000)	[2] Offering Price	[3] Under-writing Discount [ii]	[4] Offering Expense ($000)	[5] Net Proceeds Per Share	[6] Total Flotation Costs ($000)	[7] Gross Equity Issue Before Costs ($000)	[8] Net Proceeds ($000)	[9] Flotation Cost Percentage
MDU Resources Group	MDU	2/4/2004	2,300	23.32	0.793	350	22.37	2,174	53,636	51,462	4.05%
MDU Resources Group	MDU	11/19/2002	2,400	24.00	0.720	193	23.20	1,921	57,600	55,679	3.34%
								$ 4,095	$ 111,236	$ 107,141	3.68%

[i] Offering Completion Date
[ii] Underwriting discount is 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:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

Company	Ticker	[10] Annualized Dividend	[11] Stock Price	[12] Dividend Yield	[13] Expected Dividend Yield	[14] Expected Dividend Yield Adjusted for Flotation Costs	[15] Value Line Earnings Growth	[16] Yahoo! Finance Earnings Growth	[17] Zacks Earnings Growth	[18] Average Earnings Growth	[19] Cost of Equity: Mean Growth Rate	[20] Cost of Equity Adjusted for Flotation Costs	
Atmos Energy Corporation	ATO	$ 3.22	$ 116.59	2.76%	2.86%	2.97%	7.00%	7.40%	7.00%	7.13%	9.99%	10.10%	
NiSource Inc.	NI	$ 1.06	$ 28.41	3.73%	3.87%	4.02%	9.50%	7.40%	6.00%	7.63%	11.51%	11.66%	
Northwest Natural Gas Company	NWN	$ 1.95	$ 37.86	5.15%	5.27%	5.47%	6.50%	2.80%	n/a	4.65%	9.92%	10.12%	
ONE Gas, Inc.	OGS	$ 2.64	$ 63.07	4.19%	4.28%	4.44%	3.50%	5.00%	5.00%	4.50%	8.78%	8.94%	
Spire, Inc.	SR	$ 3.02	$ 61.46	4.91%	5.04%	5.24%	4.50%	6.36%	5.00%	5.29%	10.33%	10.52%	
Mean											10.11%	10.27%	
Median											9.99%	10.12%	
Flotation Cost Adjustment (Mean)												0.16%	[21]
Flotation Cost Adjustment (Median)												0.13%	[22]

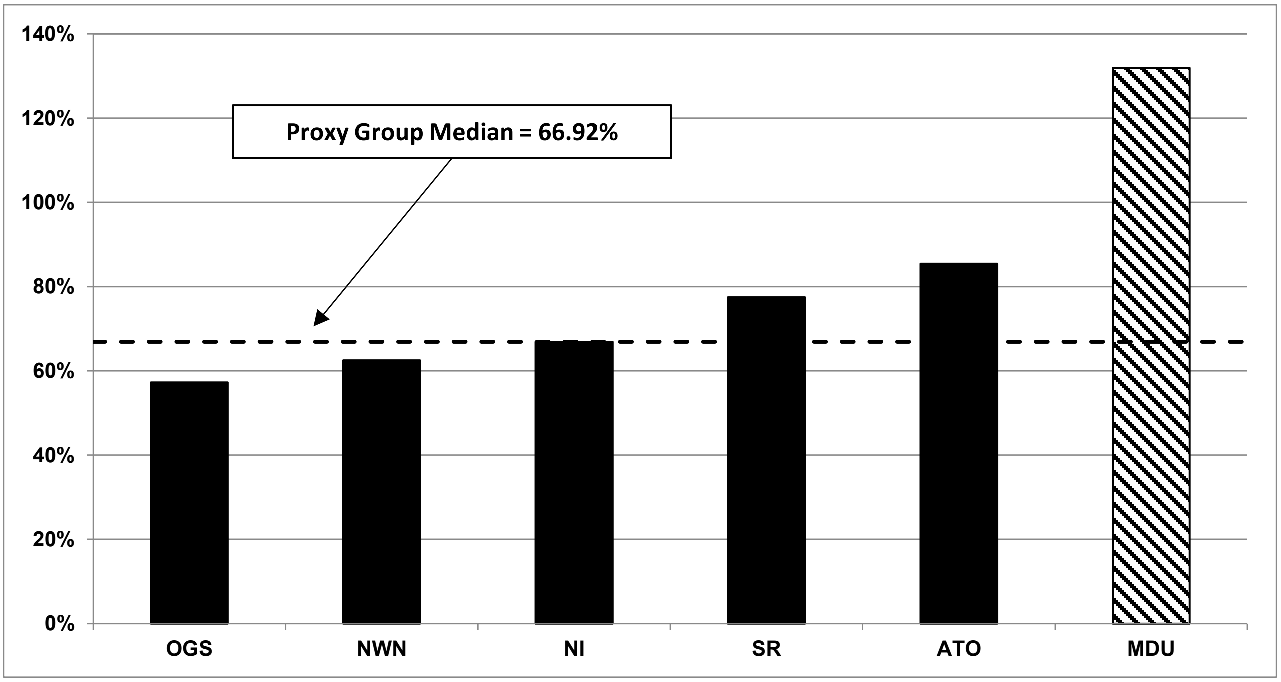
Notes:
[1] - [4] Sources: MDU Resources Group - Prospectus dated February 4, 2004 and Prospectus dated November 19, 2002.
[5] Equals [8]/[1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Bloomberg Professional
[11] Bloomberg Professional, equals 30-day average as of May 31, 2024
[12] Equals [10] / [11]
[13] Equals [12] x (1 + 0.5 x [18])
[14] Equals [13] / (1 − Flotation Cost)
[15] Value Line
[16] Yahoo! Finance
[17] Zacks Investment Research
[18] Equals Average of [15], [16], [17]
[19] Equals [13] + [18]
[20] Equals [14] + [18]
[21] Equals [20] (Mean) − [19] (Mean)
[22] Equals [20] (Median) − [19] (Median)

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2023 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2023	2024	2025	2026	2027	2028	Projected Cap. Ex. / 2023 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			$20.25	$20.25	$20.13	$20.00	$20.00	
Common Shares Outstanding			158.00	158.00	166.50	175.00	175.00	
Capital Expenditures			$3,199.5	$3,199.5	$3,350.8	$3,500.0	$3,500.0	85.4%
Net Plant		$19,607.0						
NiSource Inc.	NI							
Capital Spending per Share			$6.50	$6.50	$6.63	$6.75	$6.75	
Common Shares Outstanding			450.00	450.00	450.00	450.00	450.00	
Capital Expenditures			$2,925.0	$2,925.0	$2,981.3	$3,037.5	$3,037.5	66.9%
Net Plant		$22,275.0						
Northwest Natural Gas Company	NWN							
Capital Spending per Share			$9.50	$9.50	$9.75	$10.00	$10.00	
Common Shares Outstanding			41.00	41.00	43.00	45.00	45.00	
Capital Expenditures			$389.5	$389.5	$419.3	$450.0	$450.0	62.5%
Net Plant		$3,358.0						
ONE Gas, Inc.	OGS							
Capital Spending per Share			$12.15	$12.15	$12.38	$12.60	$12.60	
Common Shares Outstanding			56.50	56.50	56.75	57.00	57.00	
Capital Expenditures			$686.5	$686.5	$702.3	$718.2	$718.2	57.2%
Net Plant		$6,135.2						
Spire, Inc.	SR							
Capital Spending per Share			$13.90	$13.90	$14.20	$14.50	$14.50	
Common Shares Outstanding			60.00	60.00	63.03	66.05	66.05	
Capital Expenditures			$834.0	$834.0	$895.0	$957.7	$957.7	77.5%
Net Plant		$5,778.9						
Montana-Dakota Utilities Co.	MDU							
Capital Expenditures [8]			$22.73	$37.88	$34.99	$25.01	$21.32	132.0%
Net Plant [9]		$107.5						

Notes:
[1] - [6] Value Line, dated May 24, 2024
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Company Provided Data
[9] Company Provided Data

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2023 NET PLANT



Projected CAPEX / 2023 Net Plant

Rank	Company		Percent
1	ONE Gas, Inc.	OGS	57.2%
2	Northwest Natural Gas Company	NWN	62.5%
3	NiSource Inc.	NI	66.9%
4	Spire, Inc.	SR	77.5%
5	Atmos Energy Corporation	ATO	85.4%
6	Montana-Dakota Utilities Co.	MDU	132.0%
	Proxy Group Median		66.92%
	MDU as % of Median		1.97

Notes:
Source: Schedule 11, pp. 1 col. [7]

COMPARISON OF
REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Overall Revenue Stabilization	[6] Capital Cost Recovery
Atmos Energy Corporation									
	Atmos Energy Corporation	Kansas	Gas	Historical	Partial	No	No	Yes	Yes
	Atmos Energy Corporation	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Atmos Energy Corporation	Louisiana	Gas	Historical	Partial	Yes	No	Yes	No
	Atmos Energy Corporation	Mississippi	Gas	Historical	Partial	Yes	No	Yes	Yes
	Atmos Energy Corporation	Tennessee	Gas	Historical	Partial	Yes	No	Yes	No
	Atmos Energy Corporation	Texas	Gas	Historical	Partial	Yes	No	Yes	Yes
NiSource Inc.									
	Northern Indiana Public Service Co.	Indiana	Electric	Fully Forecast	Partial	No	No	Yes	Yes
	Northern Indiana Public Service Co.	Indiana	Gas	Fully Forecast	No	No	No	No	Yes
	Columbia Gas of Kentucky Inc.	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Maryland Inc.	Maryland	Gas	Partially Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes
	Columbia Gas of Pennsylvania Inc.	Pennsylvania	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Virginia Inc.	Virginia	Gas	Historical	Partial	No	No	Yes	Yes
Northwest Natural Gas Company									
	Northwest Natural Gas Co.	Oregon	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Northwest Natural Gas Co.	Washington	Gas	Historical	No	No	No	No	No
ONE Gas, Inc.									
	Kansas Gas Service Co.	Kansas	Gas	Historical	Partial	No	No	Yes	Yes
	Oklahoma Natural Gas Co.	Oklahoma	Gas	Historical	Partial	Yes	No	Yes	No
	Texas Gas Service Co. Inc.	Texas	Gas	Historical	Partial	Yes	No	Yes	Yes
Spire, Inc.									
	Spire Alabama Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	Yes	No
	Spire Gulf Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	Yes	No
	Spire Missouri Inc.	Missouri	Gas	Partially Forecast	Partial	No	No	Yes	Yes

Proxy Group Totals	Fully Forecast	8				
	Partially Forecast	3	Yes	19	Yes	15
	Historical	10	No	2	No	6
	% Forecast	52.4%	% Yes	90.5%	% Yes	71.4%

Company	State	Utility Type	Test Year Convention	Revenue Decoupling	Formula-Based Rates	Straight Fixed Variable Rate Design	Overall Revenue Stabilization	Capital Cost Recovery
Montana-Dakota [7]	Montana	Gas	Historical	No	No	No	No	No

Notes:
[1] Regulatory Research Associates, Rate Case History, Company Tariffs, Company Form 10-K.
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[3] Company Form 10-K, Company Tariffs, S&P Capital IQ Pro
[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[7] Data provided by the Company

COMPARISON OF
RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
Ultimate Parent Company	Jurisdiction	Rank	Numeric Rank
Alliant Energy Corporation	Kansas	Below Average/1	7
	Kentucky	Average/2	5
	Louisiana	Average/2	5
	Mississippi	Above Average/3	3
	Tennessee	Above Average/3	3
	Texas RRC	Average/1	4
NiSource Inc.	Indiana	Average/1	4
	Kentucky	Average/2	5
	Maryland	Below Average/2	8
	Ohio	Average/2	5
	Pennsylvania	Above Average/2	2
	Virginia	Average/1	4
Northwest Natural Gas Company	Oregon	Average/2	5
	Washington	Average/3	6
ONE Gas, Inc.	Kansas	Below Average/1	7
	Oklahoma	Average/3	6
	Texas RRC	Average/1	4
Spire, Inc.	Alabama	Above Average/1	1
	Missouri	Average/3	6
Proxy Group Average		Average/1 - Average/2	4.74
Montana-Dakota Utilities Co.	Montana	Below Average/1	7

Notes
[1] State Regulatory Evaluations, Regulatory Research Associates, March 1, 2024.
[2] AA/1= 1, AA/2= 2, AA/3= 3, A/1= 4, A/2= 5, A/3=6, BA/1= 7, BA/2= 8, BA/3= 9

COMPARISON OF
S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
Ultimate Parent Company	Jurisdiction	Rank	Numeric Rank
Alliant Energy Corporation	Kansas	Highly credit supportive	2
	Kentucky	Most credit supportive	1
	Louisiana	Highly credit supportive	2
	Mississippi	Very credit supportive	3
	Tennessee	Highly credit supportive	2
	Texas RRC	Highly credit supportive	2
NiSource Inc.	Indiana	Highly credit supportive	2
	Kentucky	Most credit supportive	1
	Maryland	Very credit supportive	3
	Ohio	Very credit supportive	3
	Pennsylvania	Highly credit supportive	2
	Virginia	Highly credit supportive	2
Northwest Natural Gas Company	Oregon	More credit supportive	4
	Washington	Very credit supportive	3
ONE Gas, Inc.	Kansas	Highly credit supportive	2
	Oklahoma	Very credit supportive	3
	Texas RRC	Highly credit supportive	2
Spire, Inc.	Alabama	Most credit supportive	1
	Missouri	Very credit supportive	3
Proxy Group Average		Highly credit supportive - Very credit supportive	2.26
Montana-Dakota Utilities Co.	Montana	More credit supportive	4

Notes

[1] S&P Global Ratings, "North American Utility Regulatory Jurisdictions Update: Ontario Remains Unchanged, Notable Developments Elsewhere," March 11, 2024.
[2] Most Credit Supp. = 1, Highly Credit Supp. = 2, Very Credit Supp. = 3, More Credit Supp. = 4, Credit Supp. = 5

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
NiSource Inc.	NI	54.17%	54.85%	54.43%	54.48%
Northwest Natural Gas Company	NWN	47.72%	44.08%	41.92%	44.57%
One Gas Inc.	OGS	58.24%	61.09%	60.04%	59.79%
Spire Inc.	SR	47.30%	49.08%	52.75%	49.71%
Proxy Group					
MEAN		53.49%	53.80%	53.49%	53.59%
LOW		47.30%	44.08%	41.92%	44.57%
HIGH		60.01%	61.09%	60.04%	59.79%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
Northern Indiana Public Service Company LLC	NI	56.92%	58.59%	58.01%	57.84%
Columbia Gas of Kentucky, Inc.	NI	54.91%	53.87%	54.68%	54.49%
Columbia Gas of Maryland, Inc.	NI	51.96%	55.26%	54.95%	54.06%
Columbia Gas of Ohio, Inc.	NI	50.67%	50.79%	50.45%	50.64%
Columbia Gas of Pennsylvania, Inc.	NI	56.64%	56.05%	55.68%	56.12%
Columbia Gas of Virginia, Inc.	NI	44.25%	44.52%	43.69%	44.15%
Northwest Natural Gas Company	NWN	47.72%	44.08%	41.92%	44.57%
Kansas Gas Service Company, Inc.	OGS	58.37%	61.37%	60.33%	60.02%
Oklahoma Natural Gas Company	OGS	58.26%	60.99%	59.85%	59.70%
Texas Gas Service Company, Inc.	OGS	58.13%	60.98%	59.99%	59.70%
Spire Alabama Inc.	SR	52.01%	56.67%	58.82%	55.84%
Spire Gulf Inc.	SR	41.35%	41.14%	39.49%	40.66%
Spire Mississippi Inc.	SR		39.18%	38.74%	38.96%
Spire Missouri Inc.	SR	45.49%	46.20%	50.65%	47.45%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
NiSource Inc.	NI	45.83%	45.15%	45.57%	45.52%
Northwest Natural Gas Company	NWN	45.46%	44.85%	46.45%	45.59%
One Gas Inc.	OGS	41.76%	38.91%	39.96%	40.21%
Spire Inc.	SR	39.78%	39.42%	37.24%	38.82%
Proxy Group					
MEAN		42.56%	41.69%	42.18%	42.14%
LOW		39.78%	38.91%	37.24%	38.82%
HIGH		45.83%	45.15%	46.45%	45.59%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
Northern Indiana Public Service Company LLC	NI	43.08%	41.41%	41.99%	42.16%
Columbia Gas of Kentucky, Inc.	NI	45.09%	46.13%	45.32%	45.51%
Columbia Gas of Maryland, Inc.	NI	48.04%	44.74%	45.05%	45.94%
Columbia Gas of Ohio, Inc.	NI	49.33%	49.21%	49.55%	49.36%
Columbia Gas of Pennsylvania, Inc.	NI	43.36%	43.95%	44.32%	43.88%
Columbia Gas of Virginia, Inc.	NI	55.75%	55.48%	56.31%	55.85%
Northwest Natural Gas Company	NWN	45.46%	44.85%	46.45%	45.59%
Kansas Gas Service Company, Inc.	OGS	41.63%	38.63%	39.67%	39.98%
Oklahoma Natural Gas Company	OGS	41.74%	39.01%	40.15%	40.30%
Texas Gas Service Company, Inc.	OGS	41.87%	39.02%	40.01%	40.30%
Spire Alabama Inc.	SR	33.01%	40.18%	32.80%	35.33%
Spire Gulf Inc.	SR	38.77%	42.00%	57.90%	46.22%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	42.91%	39.42%	38.72%	40.35%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
One Gas Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Inc.	SR	0.00%	0.00%	0.00%	0.00%
Proxy Group					
MEAN		0.00%	0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%	0.00%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS	0.00%	0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Gulf Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	0.00%	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

SHORT-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	6.82%	11.07%	11.63%	9.84%
One Gas Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Inc.	SR	12.92%	11.49%	10.01%	11.47%

Proxy Group					
MEAN		3.95%	4.51%	4.33%	4.26%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		12.92%	11.49%	11.63%	11.47%

SHORT-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	6.82%	11.07%	11.63%	9.84%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS	0.00%	0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	14.98%	3.15%	8.38%	8.83%
Spire Gulf Inc.	SR	19.88%	16.86%	2.61%	13.12%
Spire Mississippi Inc.	SR		60.82%	61.26%	61.04%
Spire Missouri Inc.	SR	11.60%	14.38%	10.63%	12.20%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2024.05.061

Direct Testimony

Of

Jesse Volk

Q. Please state your name and business address.

A. My name is Jesse Volk, and my business address is 705 West Fir Avenue, Fergus Falls, Minnesota 56537.

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

A. I am the System Integrity Manager 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 am responsible for the management of the Transmission and Distribution Integrity Management programs and Integrity Replacement projects, which includes the System Safety and Integrity Program (SSIP).

Q. Please outline your educational and professional background.

A. I am a graduate of South Dakota School of Mines and Technology with a Bachelor of Science Degree in Civil Engineering. I am also a registered professional engineer with the State of North Dakota.

I began my career in 2007 as a gas engineer with Montana-Dakota in Dickinson, North Dakota. Since that time, I have held various positions of increasing responsibilities throughout the gas operations and engineering departments across the eight states of Idaho, Minnesota, Montana, North Dakota, Oregon, South Dakota, Washington, and Wyoming.

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

A. Yes, I have testified before the North Dakota Public Service Commission and the Minnesota and South Dakota Public Utilities Commissions.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) provide an overview of the Company's SSIP; (2) provide an overview of the Company's SSIP projects that were completed since the last rate case and those currently in progress; and (3) the gas metering process as it relates to SSIP.

<u>OVERVIEW OF SYSTEM SAFETY AND INTEGRITY PROGRAM</u>

Q. What is Montana-Dakota's System Safety and Integrity Program (SSIP)?

A. Montana-Dakota's SSIP is a pipeline replacement program that accounts for a substantial portion of the Company's natural gas distribution capital investment. The replacements are a direct result of the Integrity Management Program (IMP) mandated by the Pipeline and Hazardous Materials Safety Administration (PHMSA). IMP requires pipeline operators to implement a comprehensive and cost-effective process that analyzes pipelines through all stages, including engineering, design, construction, operation, inspection, repairs, and replacement.

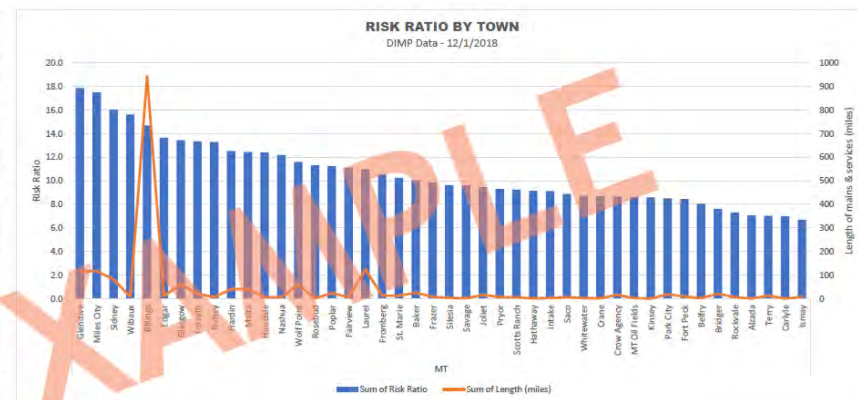
Q. How does the Company prioritize and select safety-related projects?

A. Montana-Dakota's Distribution Integrity Management Program (DIMP) assigns weightings and consequence factors to each pipeline segment based on attributes and key IMP threats. The data is analyzed through the SSIP which identifies and prioritizes Montana-Dakota's highest risk systems by state, based on the Weighted Average Risk (WAR) scores of Early Vintage Steel Pipe (EVSP) and Early Vintage Plastic Pipe (EVPP) as shown in Figure 1.

MONTANA – 2019 SSIP PLAN

Town Name	Risk Ratio[1]	Length (miles)	Town Name	Risk Ratio[1]	Length (miles)
Glendive	17.9	114.1	Silesia	9.6	3.0
Miles City	17.5	118.0	Savage	9.6	1.2
Sidney	16.0	81.4	Joliet	9.5	15.5
Wibaux	15.6	8.8	Pryor	9.3	7.2
Billings	14.7	944.8	Scotts Ranch	9.3	5.3
Edgar	13.7	12.0	Hathaway	9.1	1.8
Glasgow	13.5	61.3	Intake	9.1	1.9
Forsyth	13.4	20.8	Saco	8.9	6.4
Richey	13.3	6.3	Whitewater	8.7	2.2
Hardin	12.5	40.6	Crane	8.7	1.4
Malta	12.4	40.6	Crow Agency	8.7	16.9
Hinsdale	12.4	5.5	MT Oil Fields	8.6	2.3
Nashua	12.2	6.4	Kinsey	8.6	0.2
Wolf Point	11.6	59.6	Park City	8.5	19.4
Rosebud	11.3	1.8	Fort Peck	8.5	9.1
Poplar	11.2	23.6	Belfry	8.1	2.6
Fairview	11.1	6.4	Bridger	7.6	20.7
Laurel	11.0	123.5	Rockvale	7.3	6.6
Fromberg	10.6	13.3	Alzada	7.1	0.7
St. Marie	10.3	12.5	Terry	7.0	12.8
Baker	10.1	25.1	Carlyle	7.0	0.6
Frazer	9.9	8.2	Ismay	6.7	7.0
MT Total				13.9	1879.6

1. Risk Ratios are for EVSP & EVPP only.



Five Year Replacement Plan (2019-2023)			
Year	Town	Est. Replacement Length (miles)	Comment
2019	Glendive	16.3	Downtown EVSP replacement
	Fairview	2.7	Completed in conjunction with Fairview, ND project (only MT shown)
2020-2023	Glendive	TBD	Annual projects similar in scope to 2019

Figure 1 - SSIP MT State Plan

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 corrosion, material, weld/joint, equipment failure, incorrect operation, natural forces, outside forces, and missing data threats. If Montana-Dakota determines that replacement is an appropriate action to reduce the risk, the Company establishes a replacement project.

Q. Does the Company consider alternative ways or timeframes to meet the need for this project?

A. When feasible, Montana-Dakota works jointly with State, City, County, or general contractors performing highway, road, and underground infrastructure replacement projects within the same vicinity. This collaboration ultimately eliminates duplication of work, provides cost savings, and limits long-term interruptions to the public and Montana-Dakota's customers.

Q. How will the Company's customers benefit from the project?

A. Montana-Dakota's SSIP 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 Company's replacement of these high-risk systems ultimately increases overall public safety, lowers operating and maintenance (O&M) costs, and improves system reliability for Montana-Dakota's customers.

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. The following pages contain a description of each project, including the need for each project.

<u>MAJOR CAPITAL PROJECTS</u>

<u>Glendive SSIP 2019 - 2023</u>

Q. Would you please describe the Glendive SSIP project?

A. The Glendive SSIP project is a multi-year project focusing on the replacement of Low Pressure EVSP and EVPP natural gas mains and services with medium and high-density polyethylene (MDPE & HDPE) lines. Project replacement quantities and type are as follows:

<u>Mains</u>

2" MDPE – 130,234 feet

4" MDPE – 43,536 feet

6" MDPE – 808 feet

4" Steel – 822 feet

6" Steel – 435 feet

Totaling – 175,835 feet or 33.3 miles

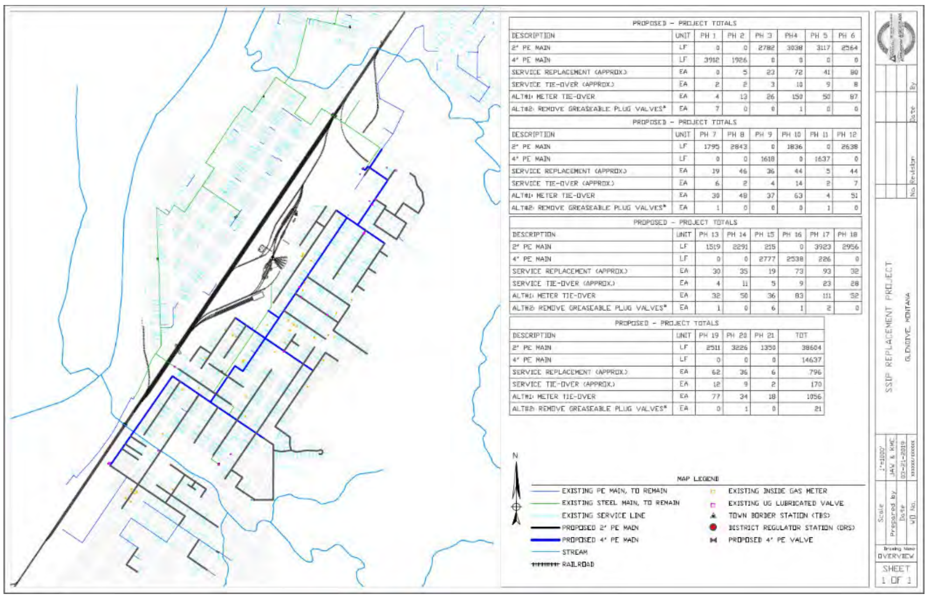
Services

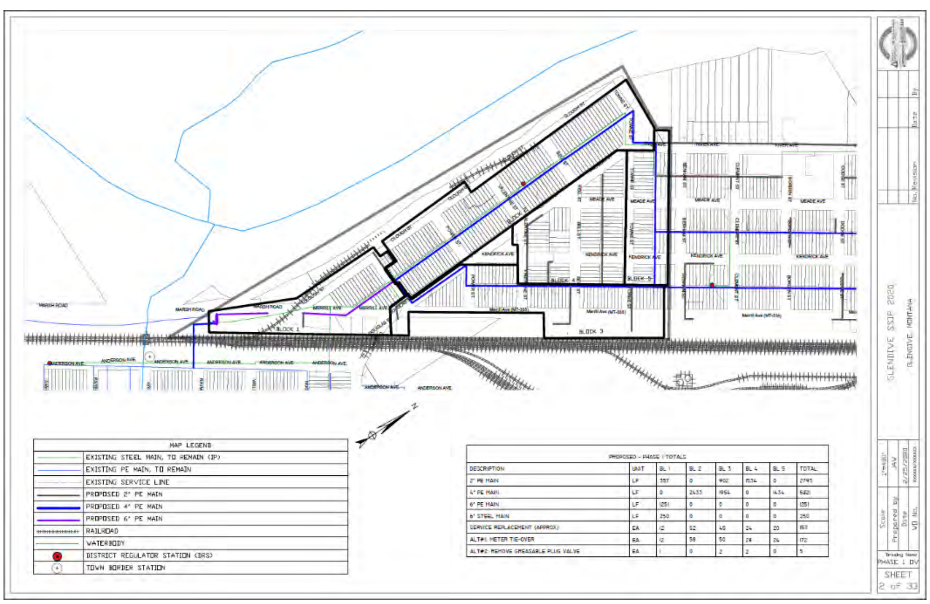
Service line quantity replaced or re-tested – 2,041

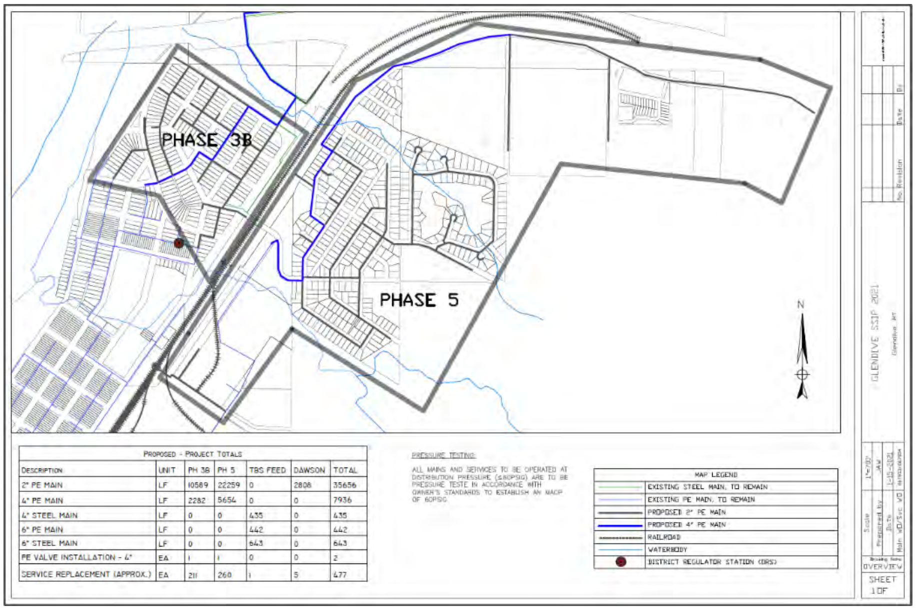
District Regulator Stations (DRS)

DRS Retired – 7

DRS Added/Replaced – 0

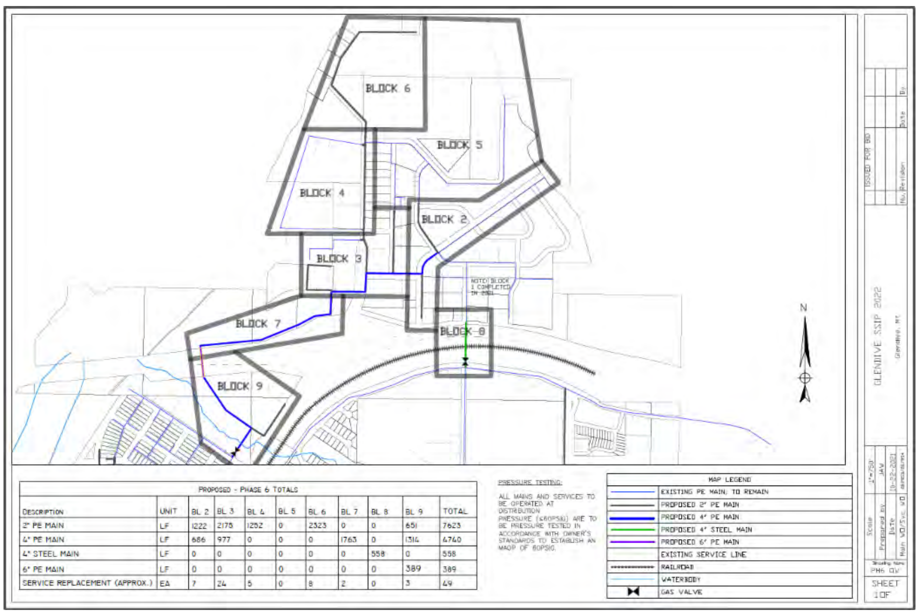






PROPOSED - PROJECT TOTALS

DESCRIPTION	UNIT	PH 3B	PH 5	TBS FEED	DAWSON	TOTAL
2" PE MAIN	LF	10589	22259	0	2808	35656
4" PE MAIN	LF	2282	5654	0	0	7936
4" STEEL MAIN	LF	0	0	435	0	435
6" PE MAIN	LF	0	0	442	0	442
6" STEEL MAIN	LF	0	0	643	0	643
PE VALVE INSTALLATION - 4"	EA	1	1	0	0	2
SERVICE REPLACEMENT (APPROX.)	EA	211	260	1	5	477



PROPOSED - PHASE 6 TOTALS

DESCRIPTION	UNIT	BL 2	BL 3	BL 4	BL 5	BL 6	BL 7	BL 8	BL 9	TOTAL
2" PE MAIN	LF	1222	2175	1252	0	2323	0	0	651	7623
4" PE MAIN	LF	686	977	0	0	0	1763	0	1314	4740
4" STEEL MAIN	LF	0	0	0	0	0	0	558	0	558
6" PE MAIN	LF	0	0	0	0	0	0	0	389	389
SERVICE REPLACEMENT (APPROX.)	EA	7	24	5	0	8	2	0	3	49

Figure(s) 2-5 - Glendive Yearly Plans

Q. Why did the Company undertake the Glendive Replacement?

A. Glendive was identified as Montana-Dakota's highest risk EVSP and EVPP natural gas system in the state of Montana in 2019 by the Company's SSIP.

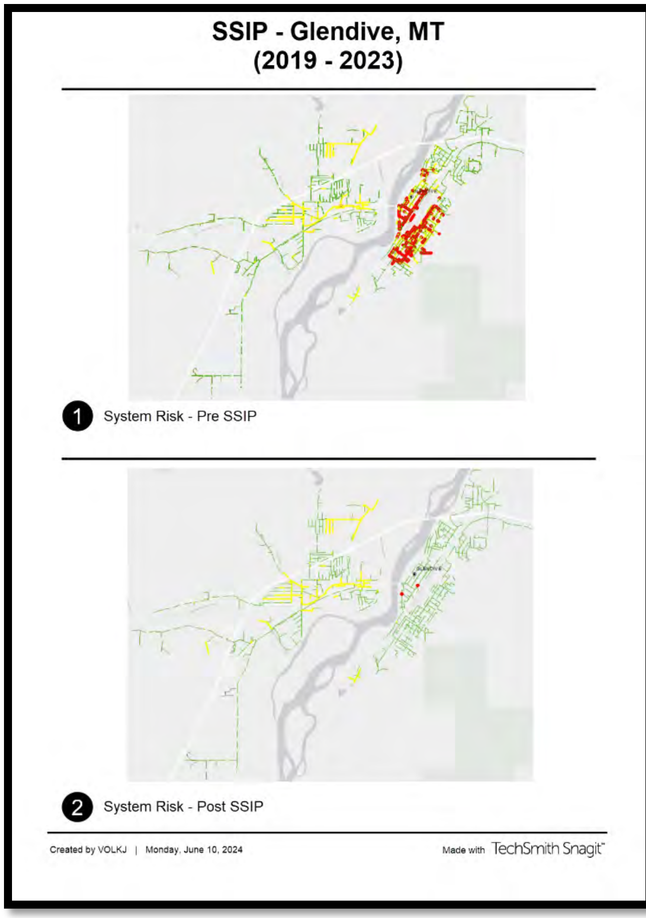


Figure 6 – Glendive DIMP Risk Comparison (Pre vs Post SSIP)

Q. What is the project timeline?

A. The current Glendive SSIP project was started in 2019 and was completed in 2023.

Q. What are the costs of the project?

A. Project costs through December 31, 2023 are as follows:

	2019	2020	2021	2022	2023	Grand Total
Main Replacements	$ 3,551,280.10	$ 2,608,060.10	$ 2,772,884.83	$ 821,029.18	$ 4,254.68	**$ 9,757,508.89**
Service Replacements	$ 3,121,861.39	$ 2,034,799.28	$ 1,746,625.62	$ 203,154.49	$ (469.63)	**$ 7,105,971.15**

<u>Hinsdale SSIP 2021</u>

Q. Would you please describe the Hinsdale SSIP project?

A. Hinsdale SSIP project was an unplanned emergency replacement to the majority of distribution system due to extensive corrosion and active leaks on steel gas main and service lines. Replacement of mains and services were completed with medium-density polyethylene (MDPE). Project replacement quantities and type are as follows:

<u>Mains</u>

2" MDPE – 10,527 feet

Totaling – 10,527 feet or 1.99 miles

<u>Services</u>

Service line quantity replaced or re-tested – 128

<u>District Regulator Stations (DRS)</u>

DRS Retired To-Date – 0

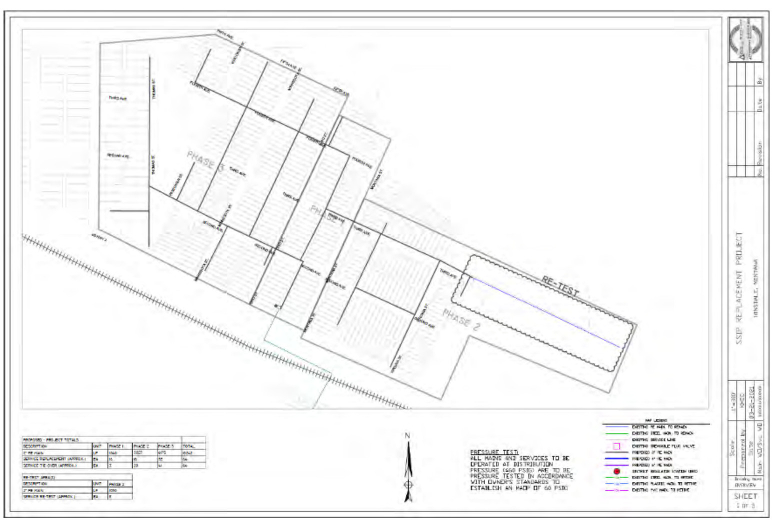


Figure 7 – Hinsdale

Q. Why did the Company undertake the Hinsdale Replacement?

A. The Hinsdale SSIP distribution system was a forced replacement due to extensive corrosion and active leaks on steel gas main and service lines.

Figure 8 – Hinsdale DIMP Risk Comparison (Pre vs Post SSIP)

Q. What is the project timeline?

A. The Hinsdale SSIP project scope started and was completed in 2021.

Q. What are the costs of the project?

A. Project costs:

		2019		2020		2021		2022		2023		Grand Total
Main Replacements	$	-	$	-	$	233,358.69	$	204.14	$	-	**$**	**233,562.83**
Service Replacements	$	-	$	-	$	394,481.80	$	(1,952.29)	$	-	**$**	**392,529.51**

Miles City SSIP 2022 – 2026 (Planned)

Q. Would you please describe the Miles City SSIP project?

A. The Miles City SSIP project is a multi-year project focusing on the replacement of Low Pressure EVSP and EVPP natural gas mains and services with medium and high-density polyethylene (MDPE & HDPE) lines. Project replacement quantities and type are as follows:

Mains

2” MDPE – 56,205 feet

4” MDPE – 2,346 feet

6” MDPE – 14,588 feet

6” Steel – 714 feet

Totaling – 73,853 feet or 13.9 miles

Services

Service line quantity replaced or re-tested – 1,073

District Regulator Stations (DRS)

DRS Retired To-Date – 0

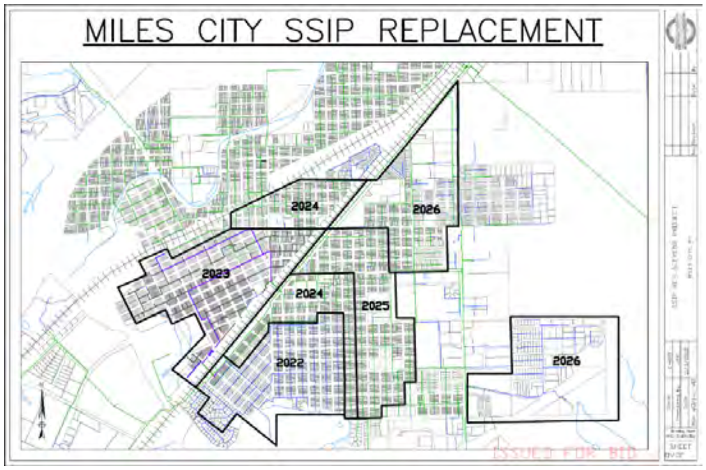


Figure 9 – Miles City

Q. Why did the Company undertake the Miles City Replacement?

A. Miles City was identified as Montana-Dakota's highest risk EVSP and EVPP natural gas system in the state of Montana in 2021 by the Company's SSIP.

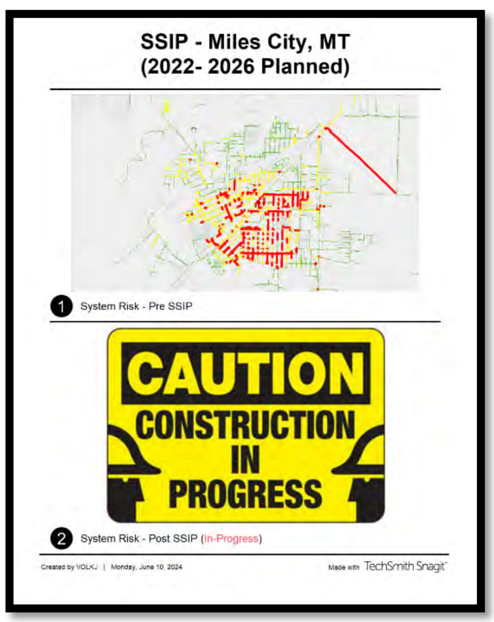


Figure 10 – Miles City DIMP Risk Comparison (Pre vs Post SSIP)

Q. What is the project timeline?

A. The Miles City SSIP project scope is a multi-year project starting in 2022 with an expected completion of 2026.

Q. What are the capital cost estimates of the project?

A. The project costs for 2022 and 2023 are as follows:

	2022	2023
Mains Replacements	$ 1,998,224	$ 3,346,593
Service Replacements	$ 1,798,406	$ 2,341,204

The current capital costs are shown as FP-316057 and FP-316062 on Rule 38.5.124, Statement C, page 5 as $2,655,199 and $2,103,566.

Q. Does the Company expect SSIP efforts to continue?

A. Pipeline operators have a requirement to implement IMPs that evolve and mature to fit an operator's unique operating environment. The evolution of an operator's IMP program takes time and resources to collect and analyze data to accurately identify the most current high-risk pipelines within any given system. Once a system is prioritized and selected it typically requires multiple years to develop and execute an action plan for full remediation or replacement.

Based on this information, Montana-Dakota expects the SSIP program to continue for the foreseeable future.

<u>SSIP Gas Metering Process</u>

Q. Would you please describe how gas metering was addressed in SSIP projects?

A. SSIP meter-piping work in Montana, was primarily addressed using third-party contractors. All meter-piping contractors were required to be enrolled and obtain operator qualifications (OQ) per OPS 7 of MDUG's Policy & Procedures prior to the commencement of work.

Q. What are the primary responsibilities of the Meter-Piping Contractor?

A. Meter-Piping Contractor responsibilities include the following:

Schedule daily appointments with customers, construct new meter set & re-install existing gas meter to Montana-Dakota Utilities' jurisdictional piping, perform metering start up testing requirements (verify odorant, leak/soap testing, and meter motion test), connect customer piping to Montana-Dakota provided customer valve, paint all applicable jurisdictional and non-jurisdictional piping and fittings, relight customer appliances per manufacturer specs, Identify hazardous conditions or red tag requirements, and complete Montana-Dakota provided G-PRTEST form for each meter.

Q. How are costs captured for SSIP meter work?

A. Meter-Piping costs are considered an operation expense under FERC 878 (Meter and house regulator expenses). The account includes costs of labor, materials used and expenses incurred in connection with removing, resetting, changing, testing, and servicing customer meters and house regulators.

Q. Does this complete your direct testimony?

A. Yes, it does.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ *Jesse Volk*

Jesse Volk
System Integrity Manager

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2024.05.061

Direct Testimony
of
Shawn Nieuwsma

Q. Please state your name and business address.

A. My name is Shawn Nieuwsma, and my business address is 400 North 4th Street, Bismarck, ND 58501.

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

A. I am the Director of Gas Supply for Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company") and Great Plains Natural Gas Co. ("Great Plains").

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

A. As the Director of Gas Supply, I am responsible for the development and execution of the Company's natural gas commodity and services portfolio. I also have managerial responsibility and oversight of natural gas scheduling/balancing, demand forecasting/modeling, and large volume customer measurement data acquisition. Our department's primary purpose is to ensure the delivery of natural gas to our city gates at our customers' service level expectations in a cost-effective manner.

Q. Please outline your educational and professional background.

A. I graduated from North Dakota State University with a Bachelor of Science degree in Industrial Engineering and Management. In June 2015, I completed the Utility Executive Course at the University of Idaho in Moscow, ID.

I started my career with Montana-Dakota in 2011 as a Gas Supply Analyst. During my tenure with the Company, I increased my level of responsibilities to Gas Supply Engineer, Gas Supply Manager and now to my current position as Director, Gas Supply.

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

A. Yes. I have previously presented testimony before the Minnesota Public Utilities Commission and the North Dakota Public Service Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain how Montana-Dakota determines a need to increase the capacity ("upgrade") to a Town Border Station (TBS) and to summarize two specific TBS upgrades.

<u>OVERVIEW OF TOWN BORDER STATION (TBS) REVIEW PROCESS</u>

Q. Please describe the term TBS as it applies to your testimony.

A. A TBS refers to relief, regulation, metering, and other applicable facilities related to custody transfer of natural gas between a transportation service provider (TSP)[1] and a local distribution company. I will use TBS when referring to delivery point[2] or city gate because they have generally the same meaning in the context of this testimony.

Q. Please describe Firm Transportation Service Capacity and its value to customers.

A. Firm Transportation Service Capacity (Contract Capacity) is held through firm transportation service agreements (FTSAs) with TSPs to 1.) receive natural gas on the TSP's transmission system and 2.) to deliver natural gas to and through contractually defined TBSs. Firm is the highest level of service (highest priority) and is practically limited to the engineering-determined Design Capacity of a TBS. Utilities' primary customers do not have immediate access to alternative heating energy sources; therefore, using this highest priority of service is the best way to ensure energy delivery all year and in any conditions.

Q. Please describe the process the Company uses to determine Contract Capacity requirements to a TBS.

A. The first step is to calculate design day delivery requirements. Historical consumption (energy) is recorded at each TBS and is regressed against corresponding heating degrees to create a regression formula[3]. Design heating degrees[4] are applied to this formula yielding a design day

[1] The only applicable TSP for this testimony is WBI Energy Transmission (WBI).
[2] Delivery point is more appropriate when describing contractual transportation capacity because such capacity may include multiple TBSs. Laurel has multiple TBSs, Sidney has one.
[3] Calculation and use of formula will or will not include interruptible load depending on application of formula.
[4] Highest heating degrees in past 30 years.

demand. This evaluation is performed on an annual basis or sub annually as needed.

The Company then compares each TBS's Design Day Demand to its Contract Capacity. Montana-Dakota should consider acquiring incremental Contract Capacity if a TBS's firm Design Day Demand exceeds its Contract Capacity and consider TBS upgrades if required Contract Capacity is greater than Design Capacity.

Q. Why might Design Day Demand change?

A. Design Day Demand dynamics are driven by changes to both/either customer count and/or customer usage patterns. Typically, communities with limited growth realize limited design day demand changes. Larger and growing communities, particularly those with large commercial and industrial growth may see design day demand increases each year.

In rare circumstances, Design Day Demand can decrease. This is observed and addressed in communities with a declining population or communities that have lost load through efficiency improvements or customer departure.

Q. Has Montana-Dakota seen load growth that has increased its Design Day Demand?

A. Yes, load growth has been realized in various locations throughout the Company's service territory.

Q. Has this load growth cause any TBS's Design Day Demand to exceed Contract Capacity?

A. Yes, such growth has driven some TBS's Firm Design Day Demand above the subscribed Contract Capacity or to a level below the targeted Reserve Margin.

Q. What is meant by Reserve Margin?

A. Reserve Margin refers to the amount of Contract Capacity above the Firm Design Day Demand intended to provide a level of safety for unaccounted load growth, new design heating degrees, TSP fuel-in-kind, and regression error. Montana-Dakota's Contract Capacity target is 5%-10% above the Design Day requirement. This amount strikes a balance between ensuring that all firm customers are served on a Design Day[5] while avoiding costs for unnecessary Contract Capacity.

Q. Have there been any methodology changes to the calculation of Firm Design Day Demand or use of Reserve Margin in recent history?

A. No, the practice of using linear regressions to calculate Firm Design Day Demand and the use of a 5%-10% reserve margin has been used effectively for the duration of my career.

[5] Allows for slightly colder than current design day temperatures and considers design day demand formula error. Also allows for consideration of applied fuel and lost and unaccounted for percentages.

Q. How is incremental Contract Capacity typically acquired for a particular TBS?

A. Incremental Contract Capacity to a particular TBS is typically acquired by reallocating Contract Capacity from one TBS with sufficient Reserve Margin to a deficient TBS. This strategy works well when a larger TBS, with an acceptable Reserve Margin can sacrifice capacity to a smaller, deficient TBS. There is relatively little negative impact on the larger TBS and relatively high impact to the smaller TBS.

This reallocation of Contract Capacity may be done if the two involved TBS's have common upstream facilities/constraints, and the acquiring TBS has adequate Design Capacity. All customers benefit from these reallocations by avoiding incremental FTSA costs through the optimization of currently held capacity.

When Contract Capacity to a deficient TBS cannot be reallocated due to upstream facility constraints[6] or insufficient Design Capacity, a project involving facility expansion is required. Montana-Dakota will engage in transmission-level projects when upstream facility constraints exist[7]. The Company pursues individual TBS upgrades when Contract Capacity cannot be reallocated to a deficient TBS due strictly to Design Capacity limitations. Costs associated with the TBS upgrade are required

[6] Upstream facility constraints include but are not limited to compression limitations and pipeline capacity,
[7] For example, the recent "Line Section 22 Expansion" added 15,500 Mcf/day providing incremental Contract Capacity to several communities across South Central Montana.

regardless of upstream facility enhancements; therefore, Montana-Dakota strives to avoid upstream facility enhancement costs if possible.

Most transmission-level projects are completed and paid for through an incremental FTSA through which the shipper pays the TSP through tariff or negotiated rate schedules. When Montana-Dakota participates in such projects, costs of such are recovered through the monthly Gas Cost Tracking Adjustment. When there is not an incremental FTSA, costs are outside the scope of the Gas Cost Tracking Adjustment and therefore capitalized by the Company.

Q. Can Contracted Capacity exceed a TBS's Design Capacity?

A. No, Contracted Capacity (firm) is limited to the TBS's Design Capacity.

Q. How is a TBS's Design Capacity determined?

A TBS's Design Capacity is determined by calculating the volumetric throughput of the most restrictive component(s) within a TBS against a variety of system-wide operating conditions. Particularly important is the TSP's guaranteed minimum delivery pressure of 200 psi, which is used throughout the system. Other considerations include but are not limited to natural gas velocity, outlet pressure, required pressure reduction, and in-line heating.

Q. What, if any changes, have been made to how TBS Design Capacity is determined?

A. With safety and reliability in mind, Design Capacity reviews are performed by the owner of each TBS. WBI Energy Transmission Inc. (WBI) has reported that several TBSs have undergone recent evaluations with a desire to lower gas velocity. Specifically, WBI has decreased its target velocity from 120 feet/second to 70 feet/second. This target was changed to reduce pipe and other component vibration, particularly at aging TBSs. Many of WBI's TBSs are the original facilities installed at the time transmission was extended to the served community.

Q. Are there any other factors that have caused Design Day Demand to exceed Design Capacity?

A. Yes. As part of an ongoing initiative to better monitor and control the transmission system, WBI has and continues to install higher frequency measurement equipment at many TBSs. Specifically, WBI is now acquiring high-frequency (daily or sub-daily) measurement information where previous low-frequency measurement (weekly or monthly) was captured.

Q. How has read frequency increased Design Day Demand?

A. Increasing measurement read frequency (granularity) exposes its audience to a greater level of volatility. Both measurement peaks and valleys are exposed, particularly peaks because consumption ceilings are only determined by design cold conditions whereas most communities have a built-in base demand.

When measurement is acquired on a weekly or monthly basis, daily consumption was the sum of the read change divided by the number of days in the read period. Enhanced measurement granularity naturally exposes peaks, which typically only last a day or two.

Newly available peak measurement information creates new formulas from which Design Day Demand is calculated. This tends to increase the Design Day Demand and increases the contractual standard to which the Company must adhere.

Q. Why would read frequency be increased at a TBS?

A. Higher read frequency allows for better understanding and control of a transmission or distribution system. Daily measurement information allows a TSP to react more effectively to changes in operating conditions. Also, natural gas is transacted and scheduled daily so the ability to allocate flow on the same daily basis is normal throughout the industry, particularly as transmission capacity continues to grow scarcer.

IDENTIFIED NEED FOR TBS UPGRADE

Q. Have you identified any TBSs that requires a physical upgrade? If so, which TBSs?

A. Yes, the Company has identified and prioritized two Montana TBSs that require or will require a TBS upgrade. Those TBSs are Park City and Sidney.

Q. Please compare the Firm Design Day Demand to the Contract Capacity and Design Capacity for each of these TBSs.

A. All units are dekatherms/day[8].

[8] Capacity adjusted from volume to energy using applicable BTU of delivered natural gas. Effective June 1, 2024.

TBS	Design Day Demand	Contractual Capacity	Design Capacity	Contractual Reserve Margin
Park City / Laurel	5,287	4,606	4,606	-12.9%
Sidney	4,578	4,403	4,403	-3.8%

Park City TBS Upgrade

Q. Please describe the relationship between the Park City TBS and the Laurel TBS as it relates to upstream transportation capacity.

A. Park City and Laurel's distribution systems are integrated into a singular network through various ties. Therefore, gas may physically flow through the Laurel TBS and be ultimately consumed by a customer in Park City and vice versa. When these flow possibilities are present, the upstream TSP typically sells capacity to both delivery points as a singular and aggregated location.

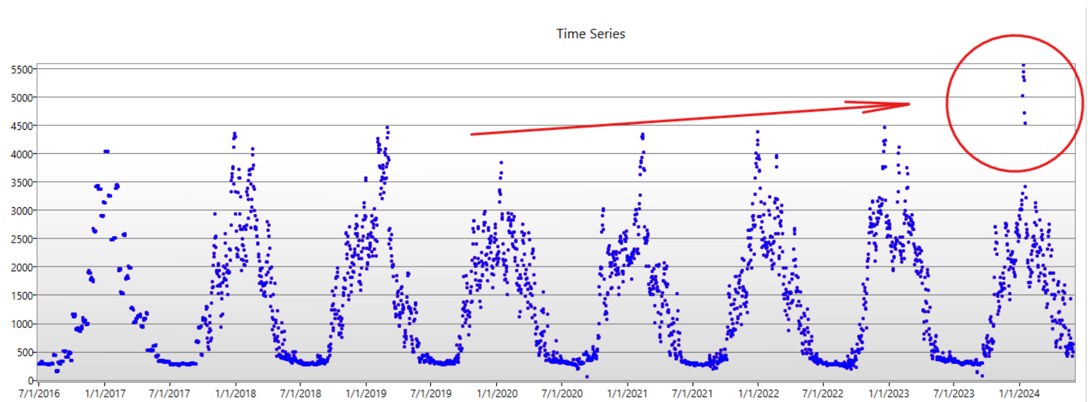
As a result, Montana-Dakota evaluates its capacity requirements for Park City and Laurel, and subscribes to transmission capacity, in aggregate. The following dialog will refer to Park City; however, the provided data will be referring to an aggregation of Park City and Laurel[9].

[9] This aggregation also includes a TBS referred to as Sunny Valley. Sunny Valley is relatively small and largely inconsequential to these discussions.

Q. Please summarize the reasons for prioritizing a Park City TBS upgrade.

A. 1) Park City (Laurel) TBS currently resides at a -12.9% reserve margin. This reserve margin is below the standard target of 5%-10%.

2) Design Day Demand has increased significantly in the past five years. Particularly large load increases were realized during the 2023-2024 Heating Season where daily firm load surpassed 5,500 Dth during



January 2024. This accelerated the growth that had been occurring since 2020. The following graph displays daily firm load in Laurel since 2016.

3) Montana-Dakota reviews customer count on a regular basis. To demonstrate Laurel's growth, the following table was assembled.

Customer Class	July 2016	May 2024	Growth
Residential	3,969	4,282	7.9%
Commercial	312	376	20.5%

Montana-Dakota believes this growth will continue and TBS capacity, both Contract and Design, will be required to continue supporting this growth.

Q. What is the expected cost for the Park City TBS upgrade?

A. The cost of the Park City TBS upgrade is $1,435,923 on FP-320067, $239,301 on FP-320088, and $1,005,707 on FP-322026, as shown on Rule 38.5.124, Statement C, pages 4 and 6.

Q. Why was an upgrade of Park City selected instead of Laurel?

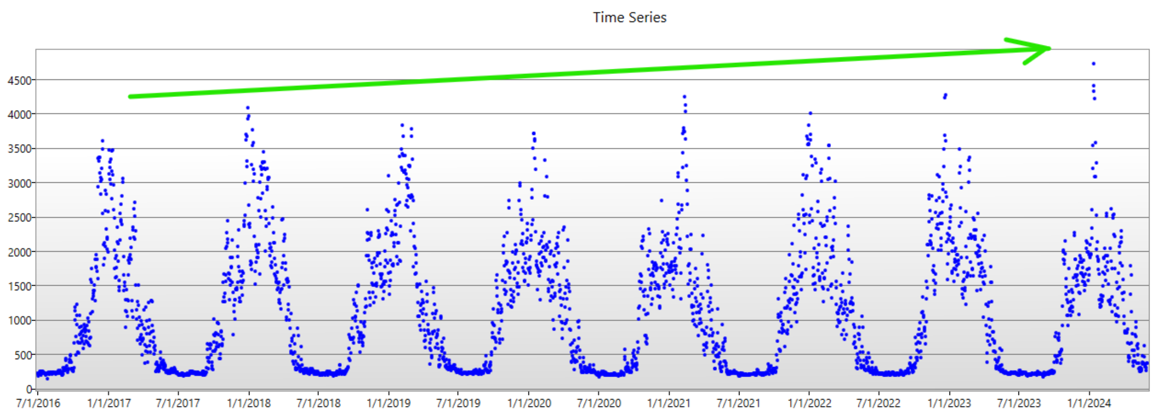
A. Park City was preferred to Laurel as an upgrade option because of the integrated distribution reliance compared to capability of each station. Load growth proximity to the Park City TBS has been significant leading to greater current and future dependence on Parker City TBS compared to historical dependence.

<u>Sidney TBS Upgrade</u>

Q. Please summarize the reasons for prioritizing a Sidney TBS upgrade.

A. 1) Sidney currently has a -3.8% reserve margin. A negative reserve margin implies that there is insufficient transportation capacity to serve firm load on a design day.

2) Sidney's firm customer consumption has been on an upward trajectory since 2010, experiencing increasing winter peak consumption nearly every year. The following graph displays each day's firm consumption since July 2016.



The realized maximum firm consumption occurred on January 13, 2024. On this date, Sidney's firm consumption was 4,723 Dth against 87 heating degrees[10].

Q. What is the expected cost for the Sidney TBS upgrade?

A. The cost of the Sidney TBS upgrade is $450,000 on FP-323741, as shown on Rule 38.5.124, Statement C, page 6.

<u>Summary of Projects</u>

Q. What alternative options to TBS upgrades has the Company considered?

A. There are two primary alternatives that the Company has considered. These are converting large firm customers to interruptible service and/or curtailing incremental customer growth.

Q. What issues does the Company have with converting customers from a firm to an interruptible level of service?

A. The lower costs associated with interruptible service no longer has

[10] Design Day applied for Sidney, MT is 88 heating degrees.

the appeal it once had. Customers state that the investment, operation, and maintenance of backup systems exceed the realized savings. Furthermore, most new high efficiency appliances are no longer compatible for dual-fuel application.

Q. Do you expect additional TBS upgrades in the future at other Montana communities?

A. Yes. It is likely that a combination of growth, tighter safety specifications and higher read frequency will require several TBS upgrades in the coming years.

Montana-Dakota will evaluate all options as TBS upgrades are determined to be required. Bakken through WBI and the Rockies via CIG have become fully subscribed and their capacity is highly utilized. The loss of flexibility will likely translate to more TBS upgrades through utility capital investment rather than incremental transmission capacity.

Q. Does this complete your direct testimony?

A. Yes, this completes my testimony.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ *Shawn Nieuwsma*

Shawn Nieuwsma
Director, Gas Supply

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2024.05.061

Direct Testimony

Of

Hart Gilchrist

Q. Please state your name and business address.

A. My name is Hart Gilchrist, and my business address is 555 South Cole Road, Boise, Idaho 83709.

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

A. I am the Vice President of Safety, Process Improvement, and Operations Systems of Montana-Dakota Utilities Co. (Montana-Dakota or Company), Cascade Natural Gas Corporation, and Intermountain Gas Company (Intermountain Gas), all subsidiaries of MDU Resources Group, Inc., and Great Plains Natural Gas Co., a division of Montana-Dakota, collectively the MDU Utilities Group.

Q. Please describe your duties and responsibilities with MDU Utilities Group.

A. I am responsible for the safety, technical training, Safety Management System (SMS), Quality, GIS, and Operations Systems (technology implementations and support functions) for Montana-Dakota.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Finance and Marketing from the University of Idaho and a Master of Business Administration from Boise State University. I served on the United Way of Treasure Valley Board of Directors, Boise State University College of Business and Economics Advisory Board, College of Western Idaho Foundation Board, American Gas Association Managing Committee, Northwest Gas Association Board, and Boise Chamber of Commerce Advisory Board. I began working for Intermountain Gas in 1994 as an Engineering Technician and have been in my current capacity since April 2018. Prior to advancing into my current role, I held numerous positions in the operations department.

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

A. Yes. I have previously presented testimony before the North Dakota Public Service Commission, the Public Utilities Commission of Idaho, and the Washington Utilities and Transportation Commission.

Q. What is the purpose of your testimony?

A. I will provide support for Montana-Dakota's rate case application regarding Montana-Dakota's Work and Asset Management System deployment. In my testimony I will refer to the integrated systems of

Maximo, LocusView and IQGeo as "Maximo" or Work and Asset Management System.

WORK AND ASSET MANAGEMENT

Q1. Please describe the Work and Asset Management System (Maximo)?

A. The Work and Asset Management System is the integrated management software programs of Maximo, LocusView and IQGeo. These three software programs work together to streamline and enhance all operational work processes by moving from manual processes into electronic, consistent processes enhancing compliance, record keeping and scheduling of work. Maximo is an integrated software solution that stores assets, work orders, work order tracking information, and maintenance and compliance schedules. LocusView is the high accuracy global positioning system (GPS) based hardware and software that is deployed to the field construction crews to capture the facilities being installed. LocusView sends completed installation data back to Maximo and geographic information system (GIS), which in turn updates all the company's other systems (i.e. accounting, customer databases, etc.). IQGeo is the field collection system for corrosion and leak survey. Employees capture required compliance data on our system using this tool, which then updates Maximo. Implementation of Maximo will enable Montana-Dakota to have a full, electronically driven construction process integrated with core systems, thus reducing touchpoints and data entry, along with streamlining the process in real-time.

Q2. Please describe the phases of implementation of the Work and Asset Management System (Maximo) and project timeline?

A. Montana-Dakota is in the second phase of a three-phase implementation of Maximo. The timeline for the full gas maintenance and construction implementation is 2019–2025.

The initial phase, Phase I, is the maintenance work that includes equipment maintenance and all gas compliance maintenance (e.g., corrosion control, leak survey, atmospheric corrosion survey, patrolling, measurement, and equipment maintenance). This phase was implemented in 2019-2021.

Phase II is gas distribution construction. This phase includes the full lifecycle of construction – initiate, design, estimate, plan/schedule, construct, close out and documentation of construction work. This phase will allow for the full, electronically driven construction process integrated to core systems; Phase II is being implemented in 2022-2024.

Phase III is the implementation of electric distribution, electric transmission, electric generation, and environmental sections and is planned for 2024-2025.

Phase II is the phase that is being considered in this rate case.

Q3. Why did Montana-Dakota undertake this project?

A. Maximo will provide six primary benefits:

1. Align operations business processes across the enterprise.
2. Replace fragmented and non-integrated operations technology systems/processes with one unified work and asset management system – improving efficiency of implementation and support.
3. Reduce touch points and redundancy.
4. Gain enterprise-wide insight into asset tracking, construction, maintenance, compliance, and costs. This includes tracking Operation's Key Performance Indicators (KPI's).
5. Drive consistent workflows across the enterprise, improving work product results.
6. Improve the user experience with consistent field data entry technology – lowers training needs and limits confusion and errors.

Q4. What are the expected benefits from implementation of Maximo?

A. Moving to a fully integrated electronic asset management system will provide for more accurate records, automated inspection intervals, less manual data entry and overall enhanced compliance. This also keeps the Company current with technology available with today's dynamic database systems. The fully electronic system will improve the overall quality of information being collected in the field and provide a central data repository for information related to all utility maintenance and construction activity. This will improve the safe operation of the system through higher quality gas facility installations, improved maintenance and compliance tracking, and more consistent and real-time reporting.

Q5. How will Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers will benefit from the use of a more streamlined and efficient work and asset management system through the elimination of multiple methods (paper, spreadsheets, databases) used to manage work and creates a single database repository for all work. Customers will benefit through the elimination of redundancy of systems and the inherent resources that are necessary to support multiple systems to complete the same or similar tasks. The electronic system will improve the overall quality of information being collected in the field and provide a central data repository for information related to all utility maintenance and construction activity. This will improve the safe operation of the system through higher quality gas facility installations.

Q6. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The Company did due diligence when selecting Maximo. An exploratory team was formed in 2017 and evaluated the implementation of work and asset management systems across the gas and electric utility industry. It was determined Maximo was the best choice because it is the most efficient, single platform solution, the system integrates well to disparate systems, and Maximo is mature and proven compared to other work and asset management systems. The Company visited other utilities to learn best practices for implementing work and asset management systems. This information was used to develop the phased approach and to leverage internal resources to develop expertise to support the system going forward. The strategy has worked thus far through the successful, on time and on budget implementation of Phase I and Phase II.

Q7. What are the costs of the project?

A. The cost of the Work and Asset Management system allocated to the Montana Gas jurisdiction is $1,586,289 shown as FP-100550, $288,250 shown as FP-324025, and $17,903 shown as FP-324037 on Rule 38.5.124, Statement C, page 9.

Q8. Does this complete your direct testimony?

A. Yes, it does.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ *Hart Gilchrist*

Hart Gilchrist
Vice President of Safety, Process
Improvement, and Operations Systems

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2024.05.061

Direct Testimony

Of

Eric P. Martuscelli

Q. **Please state your name and business address.**

A. My name is Eric P. Martuscelli, and my business address is 8113 West Grandridge Boulevard, Kennewick, Washington 99336.

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

A. I am the Vice President of Field Operations 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"). Collectively, "MDU Utilities Group".

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

A. I provide executive leadership, direct, and coordinate activities for the entire gas and electric distribution field operations in the MDU Utilities Group service territory. I oversee delivery of regulated products and services and provide strategic direction to managers in implementing our organization’s programs, policies, and procedures.

Q. Please outline your educational and professional background.

A. I hold a Bachelor’s Degree in Organizational Management, in the Forbes School of Business, from Ashford University. I have been in the utility industry for 32 years; 12 years in the field and 20 years in increasing levels of supervisory, managing, and leadership positions. Prior to advancing into my current role, I provided similar, executive oversight as Vice President, Operations for Cascade in Washington and Oregon.

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

A. Yes. I have previously presented testimony before the Washington Utilities and Transportation Commission and the North Dakota Public Service Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Company’s mains and service lines replacement capital projects expenditures. I will also provide testimony on the Billings Reinforcement capital project.

<u>Replacement Projects</u>

Q1. How are Mains and Service Lines Replacement projects generally forecasted?

A. Replacement capital projects are considered "blanket funding projects", meaning any single replacement capital project, under $150,000 will be allocated to the blanket funding project, throughout any given plant addition year. Alternatively, any replacement capital project estimated at $150,000 or above, is assigned to its own unique funding project and is not included in these blanket funding projects.

Q2. How are the project estimates formulated for blanket funding projects?

A. Mains and Service Lines replacement capital project estimates, for these blanket replacement funding projects, are budgeted and estimated in advance of the plant addition year. The estimates for these blanket funding projects are primarily derived from historical expense. Montana-Dakota anticipates, in any given year, that replacements of its facilities will be required, for a variety of reasons, including, but not limited to, damage, failure, or franchise/governing authority requirements. For the most part, these replacement capital projects can't always be anticipated so historical expense used to create an estimate, and each subsequent years' funding project allocation is updated accordingly.

Q3. What are the costs of the projects?

A. The costs for the Montana gas jurisdiction for Mains Replacements are $2,569,870 in 2024 and is shown on Rule 38.5.124, Statement C, page 5.

The costs for the Montana gas jurisdiction for Service Lines replacement are $1,335,457 in 2024 and is shown on Rule 38.5.124, Statement C, page 5.

<u>Billings Reinforcement Project</u>

Q1. Please describe the Billings Reinforcement Project.

A. The Billings Reinforcement Project is the new installation of approximately 7,400 feet of 6-inch polyethylene main on Grand Avenue from 41st Street W to west of 52nd St. W on Vintage Lane.

Q2. Why did the Company undertake the Billings Reinforcement Project?

A. During the winter of 2023-2024, system monitoring verified this area experienced line pressure below 2 pounds per square inch (psi) during extreme cold. This is an area where residential growth load has expanded, and this reinforcement is designed to increase line pressure to 12-15 psi during similar weather events.

Q3. What work has been performed in prior phases of the Project?

A. None. This is the first winter season that low system pressure was identified.

Q4. What is the timing of the Project?

A. Completion in the Fall 2024.

Q5. What are the expected cost of the Project?

A. The costs of the Billings Reinforcement Project is $592,832 as shown on Rule 38.5.124, Statement C, page 5 as FP-325460.

Q6. How will the Company's customers benefit from the Project?

A. With the current pressure data in hand, and with the expectation of continued growth in this area, our customers benefit from the reliability of natural gas service during cold weather events. Without this reinforcement, the Company anticipates weather induced outages due to pressure too low to maintain all customers.

Q7. Did the Company consider alternative ways or timeframes to meet the need for this Project?

A. A reinforcement is the only way to maintain adequate system pressure for similar weather-related events in this area. The Company did consider an alternate route, but it was found to be a more congested area and thus would have been more difficult and costly.

Q. Does this complete your direct testimony?

A. Yes, it does.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ Eric P. Martuscelli

Eric P. Martuscelli
Vice President of Field Operations

MONTANA-DAKOTA UTILITIES CO.

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

DOCKET NO. 2024.05.061

PREPARED DIRECT TESTIMONY OF

LARRY E. KENNEDY

Q1. Please state your name and business address.

A1. My name is Larry E. Kennedy. My business address is 200 Rivercrest Drive SE, Suite 277, Calgary, Alberta, T2C 2X5.

Q2. By whom are you employed?

A2. I am employed by Concentric Advisors, ULC.

Q3. What is your position with Concentric Advisors, ULC. ("Concentric")?

A3. I am employed by Concentric as a Senior Vice President.

Q4. On whose behalf are you submitting this Direct Testimony?

A4. I am submitting this Direct Testimony before the Montana Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. ("MDU" or the "Company"). Specifically, this testimony, on behalf of MDU, refers to the gas utility and Common assets.

Q5. Please describe your education and experience.

A5. I am a Certified Depreciation Professional, with over 40 years of regulatory plant accounting and depreciation experience, and 22 years of depreciation and plant accounting consulting to the regulated utility industry. I have advised numerous energy and utility clients on a wide range of accounting, property tax and utility depreciation matters. Many of these assignments have included the determination of the cost of appropriate annual depreciation accrual rates. I have included my resume and a summary of testimony that I have filed in other proceedings as Exhibit No. LEK-2.

Q6. Please describe Concentric's activities in energy and utility engagements.

A6. 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.

Q7. Have you testified before any regulatory authorities?

A7. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit No. LEK-2

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q8. What is the purpose of your Direct Testimony?

A8. The purpose of my Direct Testimony is to set forth the results of my full and comprehensive depreciation study of the Gas and Common plant in service MDU, as of December 31, 2021. My detailed report, including my analyses and recommendations, is provided in Exhibit No. LEK-3, titled "Calculated Annual Depreciation Rates Applicable to Gas Plant in Service as of December 31, 2021". Also, my detailed common report, including my analyses and recommendations, is provided in Exhibit No. LEK-4, titled "Calculated Annual Depreciation Rates Applicable to Common Plant in Service as of December 31, 2021". The detailed depreciation study reports were prepared by me or under my direction.

Q9. Please provide a brief overview of the analyses that led to your depreciation recommendations.

A9. In preparing the depreciation study report, I analyzed the historic plant account data of MDU to prepare an analysis of the Company's past retirement experience. I met (virtually) with the Company's management and operations representatives to determine the extent to which the historic indications would be reflective of the future retirement patterns. Lastly, I also reviewed the average service life and net salvage indications of many North American based gas utilities to test the results of my analysis against the natural gas industry peers.

Q10. How is the remainder of your Direct Testimony organized?

A10. Section II provides the scope of my study and a summary of my analyses and conclusions. This section also includes a discussion of the major causes of changes in the depreciation accrual rate and amounts as compared to the last study. Section III provides a background on utility depreciation, depreciation methods and procedures. Section IV provides concluding comments.

II. SCOPE OF THE DEPRECIATION STUDY

Q11. Please outline the Scope of the Depreciation Study.

A11. My depreciation study report sets forth the results of the depreciation study for the gas distribution, and general plant assets of the MDU Gas Division, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of investment, as of December 31, 2021. The rates and amounts are based on the Straight-Line Method, incorporating the Average Life Group Procedure applied on a Remaining Life Basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the MDU gas assets in service, as of December 31, 2021.

Q12. Please outline the information included in your depreciation study report.

A12. The depreciation study report is presented in nine (9) sections outlined as follows:

Section 1 Study Highlights, presents a summary of the depreciation study and results.

Section 2 Introduction, contains statements with respect to the plan and the basis of the study.

Section 3 Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life study.

Section 4 Calculation of Annual and Accrued Depreciation, presents the methods and procedures used in the calculation of depreciation.

Section 5 Result of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 2, 3, 4, 5, and 6.

Section 6 Retirement Rate Analysis

Section 7 Net Salvage Calculations

Section 8 Detailed Depreciation Calculations

Section 9 Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis.

Q13. Was the depreciation study prepared using generally accepted standard methods and practices?

A13. Yes. Previous depreciation studies completed for MDU utilized a widely accepted method for the study of the Company's historic data, known as the Retirement Rate Analysis Method. The Retirement Rate Analysis Method is generally accepted as the correct method to use when aged data is available for review. The aged data used in the last study, through December 31, 2015, was available to be incorporated into our database. Additional reliable aged data, for the period January 1, 2016 through to December 31, 2021, was provided by the Company and incorporated in our database. Given the availability of reliable aged data, I prepared the historic study of mortality history using the retirement rate method. A detailed discussion of the retirement rate analysis is presented in Section 9 of my depreciation study report.

Additionally, the service life study included:

- a review of MDU company practice and outlook, as they relate to plant operation and retirement;
- consideration of current practice in the gas system industry, including knowledge of service life estimates used for other gas system companies; and
- informed professional judgment which incorporated analyses of all of the above factors.

My study of the net salvage percentages was based on detailed study prepared under the standard approach, which has commonly become known as the "Traditional method". Within this method, the net salvage transactions (gross salvage proceeds, re-use salvage and costs of removal or retirement) are compared to the original cost of the item being retired. The analysis is prepared on an actual transaction year basis, for as many years as reliable data is available. The analysis then includes a series of 3-year rolling average bands, 5-year rolling average bands, and life to date bands covering all years of transactional data.

As described in later sections of this evidence, the depreciation accrual rates presented herein are based on generally accepted methods and procedures for calculating depreciation.

The methods described above are generally accepted for use in the development of depreciation rates for regulated utilities.

Q14. Please provide a summary of the results of the depreciation study.

A14. The study results in an annual depreciation expense accrual related to the recovery of original cost (i.e. excluding net salvage requirement) of $22.6 million, when applied to depreciable plant balances, as of December 31, 2021. The study results are summarized at an aggregate functional group level as follows:

Summary of Original Cost, Accrual Percentages and Amounts

Plant Group	**Original Cost**	**Annual Accrual**	
Distribution Plant	$548,934,689	3.21%	$17,637,857
General Plant	$49,954,953	9.87%	$4,931,463
Total Plant in Service	$598,889,642	3.77%	$22,569,320

Q15. How do the above depreciation rates compare to the depreciation rates from the previous study?

A15. The following chart summarizes the proposed composite depreciation rates as compared to the composite depreciation rates based on the study dated December 31, 2015.

Plant Group	Proposed Depreciation Rate	Previous Study Depreciation Rate
Distribution Plant	3.21%	4.15%
General Plant	9.87%	5.08%
Total Plant in Service	3.77%	4.23%

Q16. Please outline the reasons for the decreased composite depreciation rate for the gas distribution assets.

A16. In the circumstances of the distribution assets, the need for more negative net salvage percentages has had a depreciation rate increase impact that was lesser than the decline caused by the influence of the decreases due to the life extensions in many accounts. The following is a summary of the proposed average service life estimates compared to the currently used estimates, demonstrating the lengthening of the average service lives in three accounts.

Account	Description	Proposed Iowa Curves	Current Iowa Curves
374.2	Rights of Way	65-R3	65-R3
375.0	Distr. Meas & Reg Station Structures	55-R3	60-R3
376.0	Mains	55-R3	40-R3 to 62-R3
378.0	Meas & Reg Station Equip-General	50-R2	50-R2
379.0	Meas & Reg Station Equip-General	45-R2.5	45-R2.5
380.0	Services	50-R2.5	38-R0.5 to 47-R4
381.0	Meter & Meter Installations	31-R3	31-R3
383.0	House Regulators	58-R2.5	60-R3
385.0	Industrial Meas. & Reg. Station Equip	40-R2	40-R4
386.1	Misc. Property on Customer Premises	15-R3	15-R3

Account	Description	Proposed Iowa Curves	Current Iowa Curves
387.2	Other Equipment	30-R3	25-R3

The specific reasons for the average service life extensions for each of the large distribution accounts are discussed in Section 3.1.5 of my report. Additionally, the results of the statistical mortality study are presented, for each account, in Section 6 of my report.

Q17. Are the average service life extensions, as noted above, typical for gas distribution assets?

A17. Yes. In a number of recent depreciation studies that I have completed, I have noted that the average service life of gas distribution assets is lengthening throughout North America. While there are a number of factors causing this lengthening of life estimates, the most prevalent reason is the increased focus of utilities in maintaining and life extending the distribution infrastructure. For example, in recent years gas distribution utilities have been pro-active in services structure management and adding enhanced pipeline quality in the type of product used for services.

Likewise, I have noted that the life of distribution assets has also benefited from enhanced technology and the pro-active maintenance programs undertaken by gas distribution utilities. As such, the average service life extensions as observed in this study are consistent with my observations in a number of other gas utilities.

Q18. Please provide a summary of the current and proposed net salvage percentages for distribution plant.

A18. The following is a summary of the proposed net salvage percentages used in the depreciation rate calculations. I note that the current rates differ in many accounts from those proposed in the 2015 depreciation study. It is my understanding that the currently approved depreciation rates related to cost of removal were ultimately negotiated. Therefore, the net salvage percentage comparisons as noted below are based on the percentages as recommended in the 2015 depreciation study.

Account	**Description**	**Proposed**		**Last Depn Study (*)**	
		Net Salvage %	**Depn Rate**	**Net Salvage %**	**Depn Rate**
374.2	Rights of Way	0%	-0.02%	0%	0.00%
375.0	Distr. Meas & Reg Station Structures	0%	-0.56%	(50)%	1.09%
376.0	Mains	(55)%	1.19%	(50)%	1.06%
378.0	Meas & Reg Station Equip-General	(30)%	0.60%	(30)%	0.66%
379.0	Meas & Reg Station Equip-General	(5)%	0.07%	(15)%	0.37%
380.0	Services	(100)%	1.18%	(200)%	4.96%
381.0	Meter & Meter Installations	(20)%	1.74%	(20)%	0.96%
383.0	House Regulators	(5)%	0.13%	0%	0.00%
385.0	Industrial Meas. & Reg. Station Equip	(10)%	0.21%	(15)%	0.66%
386.1	Misc. Property on Customer Premises	0%	0%	0%	0.00%
387.2	Other Dist. Equipment	0%	0%	0%	0.00%

As noted above, the depreciation rates related to cost of removal and salvage currently used were changed significantly from the depreciation rates as proposed in the 2015 depreciation study. The current study has noted the continued trend to increased levels of recovery for cost of removal.

The detailed analysis of the net salvage estimates is provided in Section 7 of my MDU report.

Q19. Is the trend for more negative net salvage percentage, as noted above, typical for gas distribution assets?

A19. Yes. The increased amount of cost of removal expenditures is a common trend throughout North American utilities. In fact, this trend has been the most significant change noted in depreciation studies over the past five years. Accordingly, it has become the most debated topic of depreciation studies filed throughout North America, as well as being a significant topic of discussion at depreciation conferences. At the Society of Depreciation Professionals conference held in September 2018, there were four presentations regarding the large increase in cost of removal expenditures. This trend has been witnessed over virtually all electric, gas and pipeline utilities. As such, the trend witnessed in my MDU study is consistent with depreciation studies conducted across North America.

Q20. What is causing this trend to increased cost of removal of utility assets?

A20. It is generally accepted that there exist three main causes of increases.

Firstly, as the average age of utility assets continue to be extended, the impact of inflation becomes more pronounced. As the average service life has increased, the length of time between the original installation of the assets in some accounts and the estimated average time of retirement of the assets is getting longer. The net salvage percentage is calculated by dividing the costs to remove the asset in dollars of the time when the asset is removed by the original cost dollar of the time of installation. Given that the major component of cost of removal is labor, this increase in the life expectation, also results in an increased length of time that the labor associated with the removal is longer. To the extent that the average service lives for distribution assets have extended, the impact as described applies to a number of the MDU gas distribution accounts.

Secondly, the costs associated with the removal (or retirement) of utility assets must deal with increased environmental and regulatory requirements. For example, the costs related to the safe removal of existing infrastructure have greatly increased since the assets were originally installed. Additionally, the utilities are required to deal with the increased level of regulations within areas that are much more densely populated at the time of removal of the assets as compared to when the assets were originally placed into service. As distribution assets are often removed in municipal areas, the need to effectively deal with urban growth and density within the areas adds a significant cost to the removal of the assets that did not exist at the time of the original installation of the assets. When the assets were originally installed, the distribution assets were largely within greenfield developments, whereas now, when the assets are removed, the utility must deal with (for example) applications for road closures and re-routing, noise bylaws, and performing work within and around developed and landscaped yards.

Lastly, as utilities have implemented new and enhanced accounting systems, the ability to better track capital projects has improved the processes to track capital project costs more accurately. This provides the ability for direct charging labor associated to costs of removal specifically to cost of removal. Likewise, in circumstances where the utility uses an allocation of the total project costs to recognize that a portion of the capital project relates to the removal of assets, the advancements in the work order and plant accounting systems provide better information to allow the utility to better develop proper allocation factors.

Q21. Was a Common depreciation study also completed?

A21. Yes, a depreciation study was also conducted on the MDU Common assets. My detailed report, including my analyses and recommendations, is provided in Exhibit No. LEK-4, titled "Calculated Annual Depreciation Rates Applicable to Common Plant in Service as of December 31, 2021".

Q22. Please provide a summary of the results of the Common depreciation study.

A22. The study results in an annual depreciation expense accrual related to the recovery of original cost and net salvage requirement of $4.3 million, when applied to depreciable plant balances, as of December 31, 2021. The study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

Plant Group / Accounts	Original Cost	Previous Study Annual Accrual		Recommended Annual Accrual	
General Plant	$81,481,558	4.30%	$2,924,572	5.31%	$4,327,970
TOTAL	$81,481,558	4.30%	$2,924,572	5.31%	$4,327,970

III. DEPRECIATION METHODS AND PROCEDURES

Q23. How is depreciation defined for a rate regulated utility?

A23. Depreciation defined – "Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities".[1] When considering the action of the elements, my average service life recommendations have considered large catastrophic events that have occurred and impacted the life estimates of utility assets across North America through our use of peer analysis. The average service life of utilities has been influenced by events including forest fires, earthquakes, tornadoes, ice storms, windstorms, large scale flooding, fires, actions of third parties and other natural forces of nature, and these forces of retirement should be included in the determination of the average service life.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric system utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line Method of

1 Federal Energy Regulatory Commission, Part 201Defination 12.B (2020)

depreciation, which was adopted for use in my study.

Q24. Please outline the depreciation methods and procedures used in your depreciation study.

A24. The calculation of annual and accrued depreciation, based on the Straight-Line Method, requires the estimation of survivor curves and the selection of group depreciation procedures, as discussed below.

Depreciation Grouping Procedures - When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group and Equal Life Group procedures.

In the Average Life Group Procedure, the rate of annual depreciation is based on the average service life of the group. This rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group Procedure, also known as the Unit Summation Procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit. In the determination of the depreciation rates in this study, the use of the Average Service Life Procedure has been continued.

Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. This study calculates the annual and accrued depreciation using the Straight-Line Method and Average Life Group Procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account within the remaining life calculations. Amortization accounting has been continued in this study in a manner largely consistent with the prior study. The following is a summary of the proposed amortization periods compared to the currently used estimates, demonstrating the lengthening of the average service lives in two accounts.

Account	**Description**	**Proposed Amortization Period in Years**	**Current Amortization Period in Years***
391.1	Office Furniture & Equipment	15	15
391.3	Computer Equipment - PC	5	5

Account	Description	Proposed Amortization Period in Years	Current Amortization Period in Years*
393.0	Stores Equipment	30	30
394.1	Tools, Shop, & Garage Equipment	20	18
394.3	Vehicle Maintenance Equipment	20	20
395.0	Laboratory Equipment	20	20
397.1	Communication Equipment – Fixed Radios	15	15
397.2	Communication Equipment – Mobile Radios	15	15
397.3	General Telephone Communication Equipment	10	10
397.8	Network Equipment	5	5
398.0	Miscellaneous Equipment	25	20

***Year equivalent calculated based on rate after negotiated settlement.**

A detailed account of the factors considered in the selection of my recommended average service life estimates is provided in Section 3 of my depreciation study report.

Q25. Please outline any changes that you made in the depreciation method, grouping procedures or remaining life calculations as compared to previous depreciation studies.

A25. The depreciation rates calculated in this study were calculated on the same manner as used in the prior full depreciation study – i.e. using the Straight-Line Method, the Average Life Group Procedure was applied on a remaining life basis. However, I note that in the application of the remaining life basis, the prior study calculated the remaining life on a broad average basis, whereas Concentric incorporates a refinement into the remaining life calculations based on a weighted investment by vintage approach. The vintage approach weighs the calculations of remaining life on an allocation of the actual book accumulated depreciation account by the Calculated Accumulated Depreciation (CAD) factor determined for each vintage of plant in service. This method is described as a Calculated Accumulated Depreciation ("CAD") weighted calculation in the textbook Depreciation Systems, by Frank K. Wolf and W. Chester Fitch, published by the Iowa State University in 1994, under the title "Adjustments" within the Broad Group Model.

In contrast, the remaining life calculations in prior studies were based on a broad averaging of the composite remaining life. This method is also discussed as the Amortization Method in Depreciation Systems under the title "Adjustments" within the Broad Group Model.

In the manner in which I developed the remaining life calculations, the depreciation rate is established by dividing the undepreciated value of each group of assets (after consideration to the net salvage requirements) by the composite remaining life of the group of assets. Specifically, my calculations are made for each vintage surviving investment as of the date of the study (December 31, 2021), and then composited into a calculation for the account or group as a whole as compared to applying one overall composite life to all vintages as done in prior studies. My calculation requires two estimates:

1. The actual booked accumulated depreciation for each vintage within each account. Consistent with the plant accounting systems of most utilities, MDU does not track the booked accumulated depreciation reserve by vintage within each

account. Rather the depreciation expense is calculated at an account level and booked to accumulated depreciation at the same account level. As such, the accumulated depreciation by account is allocated within the account to each vintage, on the basis of the calculated accumulated depreciation by vintage. The calculated accumulated depreciation is a function of the estimated survivor curve, the average service life estimate, the net salvage estimates, and the achieved age of each vintage.

2. The estimated remaining life of each vintage within each account. The estimated remaining life of each vintage is a direct function of the achieved age of each vintage, the estimated survivor curve and the average service life estimate.

Once the above two estimates are determined (the allocated booked reserve by vintage and the average remaining life of each vintage), an annual accrual requirement for each vintage is determined by dividing the net book value for each vintage (considering the estimated future salvage requirements) by the average remaining life of the vintage. The annual requirement for each vintage is summed at the account level and divided into the sum of the accounts original cost surviving, as of December 31, 2021.

This process results in each vintage's calculated net book value to be depreciated over an appropriate remaining life. This vintage weighting on a CAD approach to the remaining life calculations is widely considered to be the most accurate. I agree and view this methodology as the correct and most appropriate calculation.

IV. CONCLUDING REMARKS

Q26. What is your conclusion with respect to MDU's proposed Depreciation expense?

A26. My conclusion is that MDU's requested depreciation rates, resulting in a composite depreciation rate of 3.77% for the Gas Division and 5.31% for the Common Plant, reasonably reflects the annual consumption of the undepreciated service value of the utility plant in service. Therefore, the use of the depreciation rates as presented in my report, by account, will provide for an appropriate amount of depreciation expense in the Company's revenue requirement. Therefore, I recommend that the proposed depreciation rates set forth in the depreciation studies, that I prepared for this proceeding, be adopted by the Commission for regulatory purposes as well as by the Company for financial reporting purposes.

Q27. Does this conclude your Direct Testimony?

A27. Yes, it does.

VERIFICATION

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/S/ *Larry E. Kennedy*

Larry E. Kennedy
Senior Vice President
Concentric Advisors, ULC.

LARRY E. KENNEDY, CDP

Senior Vice President

Mr. Kennedy has been in the pipeline, electric, gas utility and municipal infrastructure business for 40 years. As Senior Vice President, Concentric Advisors, ULC, Mr. Kennedy has provided professional consulting services to gas and electric utilities including generation facilities (including nuclear facilities), and high voltage transmission lines, large diameter transmission pipelines, railway systems and municipally owned utility systems. Previously, Mr. Kennedy was with Gannett Fleming Canada ULC, for over 17 years, where he was responsible for completing depreciation studies and provided advice related to large capital program spending and controls for many regulated North American utilities. Mr. Kennedy was also employed by Interprovincial Pipelines Limited (now Enbridge Pipelines) for 15 years in several plant accounting and regulatory positions and with Nova Gas Transmission Pipelines (now TC Energy) for three years as a Depreciation Specialist.

Mr. Kennedy has provided expert witness testimony related to depreciation, stranded costs, capital accounting issues, utility valuation, and property tax issues before several North American regulatory bodies. Mr. Kennedy has completed numerous seminars and all courses offered by Depreciation Programs, Inc. Mr. Kennedy is a member of the teaching faculty of the Society of Depreciation Professionals ("SDP") and has presented depreciation, stranded cost, and capital accounting related topics to the SDP, Canadian Electric Association, Canadian Gas Association, Canadian Property Taxpayers Association, Alberta Utilities Commission, British Columbia Utilities Commission and the Canadian Energy Pipeline Association. Mr. Kennedy is a past Society of Depreciation Professionals President.

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Representative Project Experience

- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and in 2015 for submission to the FERC (Docket No. RP15-1022-000) to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.

- Viking Gas Transmission Company - The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and

Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons, including discussion related to the long demand of natural gas.

- Midwestern Gas Transmission Company: The assignment included development of a detailed depreciation study and Testimony to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons. The Direct Testimony included significant discussion related to the topics of Decarbonization and changing political climate towards removal of fossil fuel demand forecasts.
- Enbridge Lakehead System: A Technical Update to a 2016 full depreciation study was prepared and filed with the FERC in 2021 in support of updating depreciation rate and resultant depreciation expense. The technical update also included an analysis and recommendation of a 20-year Economic Planning Horizon (Economic Life).

- Consolidated Edison Company of New York, Inc.: Mr. Kennedy co-authored a study and report which presented the results of research focusing on prior periods of transformative change and more recent discussions of policy tools that could address the impacts of climate change on the Company's electric, steam, and natural gas businesses.
- Montana-Dakota Utilities Co.: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study and associated expert testimony were submitted to the Montana Public Service Commission in 2018 and to the North Dakota Public Service Commission in 2022. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of the retirement of generation facilities due to environmental legislation and estimation of net salvage requirements.
- Commonwealth Edison Company: Mr. Kennedy sponsored extensive Rebuttal Testimony related to the average service life, net salvage estimations, and appropriate depreciation practices in a 2020 rate proceeding.
- Great Plains Natural Gas Co.: Annual updates of depreciation rates and net salvage requirements were calculated and submitted to the Minnesota Department of Commerce annually since 2017.
- National Grid USA Service Company Limited: A depreciation study was completed in 2020 for the National Grid High Voltage Direct Current (HVDC) electric interstate transmission line. The study included consideration of the average service life of the system components, the level of components of the system and the compliance of the recommended componentization to the FERC Uniform System of Accounts. The resultant study was used by the company in filings with the Federal Energy and Regulatory Commission (FERC)
- Society of Depreciation Professionals (SDP): Mr. Kennedy has presented at the annual conferences on the topic of the erosion of the regulatory compact throughout North America, the Future of Energy transition and its impacts on recovery of investment. Additionally, Mr. Kennedy is a member of the SDP teaching faculty and has lead a number of workshops on various aspects of decarbonization and has co-instructed on the topic of the future of energy.

Other Representative Project Experience

- Alberta Departments of Energy and Forestry and Agriculture: Detailed toll comparison and valuation models were developed to provide a comparison of the toll fairness of each of the Provinces Rural Electrification Associations (“REA”) to the comparable Investor Owned Utilities (“IOU”) for the 32 REA’s currently operating in Alberta. In addition to providing a toll comparison of the REA and IOU, a fair market valuation for each of the REA’s was also prepared. The final report of the toll compatibility and specific valuations were submitted to the Alberta Department of Energy and the Alberta Department of Forestry and Agriculture. Mr. Kennedy was the Responsible Officer on this project.
- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.
- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board (“Board”). Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.
- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004, additional depreciation studies were filed in 2005, 2010 and 2012, 2016 and 2018. The 2010, 2012, 2016 and 2018 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards. These studies also specifically analyzed the pace of technical change in the Alberta Electric system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- ATCO Electric: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities Inc. (NWT) and the distribution assets of Northland Utilities (Yellowknife) Inc. The ATCO Electric studies were submitted to the AUC for review, while the NWT and Northland Utilities (Yellowknife) Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to the Yukon Public Utilities Board. These studies also specifically analyzed the pace of technical and recently

have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Gas: Studies were prepared in 2010 and 2018 which were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. These studies also specifically analyzed the pace of technical change in the Alberta Gas system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006, 2011, and 2015. The 2011 and 2015 studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2016. Mr. Kennedy has also consulted on issues regarding International Financial Reporting Standards ("IFRS") compliance and required componentization.
- Enbridge Gas Distribution Inc.: Full and comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.
- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.
- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for

submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Group of Companies: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the British Columbia Utilities Commission ("BCUC") in 2005, 2010, 2011 and 2018 encompassing both the FortisBC electric and natural gas companies. FortisAlberta Inc. studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates. The most recent studies also specifically analyzed the pace of technical change in the Electric systems, and specifically considered the impacts of retirements, system modernization and technical enchantments to the assets.

- International Financial Reporting Standards ("IFRS"): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association and to the BCUC on this topic.

- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada ("NEB").

- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.

- New Brunswick Power: Mr. Kennedy completed a comprehensive depreciation review of the electric generation (including the nuclear facilities), transmission, distribution and general plant assets. The review, which was prepared for submission to the New Brunswick Public

Utilities Board, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report.

- Newfoundland and Labrador Hydro (NALCOR): Mr. Kennedy developed comprehensive depreciation studies that included the development of depreciation policy and rates for NALCOR. The studies provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 and 2017 studies were the subject of Regulatory Review in 2012 and 2019.
- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives of the regulated assets of the company's electric generation hydro and nuclear plants were completed in 2011 and 2013 and were submitted to the Ontario Energy Board for review.
- TransCanada Pipelines Limited - Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit-based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012, 2015, and 2018.
- TransCanada Pipelines Limited - Mainline Facilities: The study prepared for submission to the NEB included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta - Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002 and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional

full and comprehensive study was completed in 2011, and 2017. The 2011 study was fully supported through an appearance before the NEB in 2012.

Designations and Professional Affiliations

- Society of Depreciation Professionals -Certified Depreciation Professional
- Society of Depreciation Professionals (former President)

EVIDENCE ENTERED INTO PROCEEDINGS IN THE UNITED STATES

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	Alliance Pipeline LP	Alliance Pipeline LP	Federal Energy and Regulatory Commission	Docket No. RP15-1022
2019	Viking Gas Transmission Company	Viking Gas Transmission Company	Federal Energy Regulatory Commission	RP19-1340
2020	National Grid USA Service Company Limited	National Grid USA Service Company Limited	Federal Energy Regulatory Commission	Settled through Negotiation
2018	Great Plains Natural Gas Co.	Great Plains Natural Gas Co.	Minnesota Department of Commerce	Annual Depreciation Filing
2018	Montana-Dakota Utilities	Montana-Dakota Utilities	Montana Public Service Commission	Docket D2019.9
2019	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Cascade Natural Gas Corporation	Cascade Natural Gas Corporation	Oregon Public Utility Commission	UM - 2073
2020	Missouri-American Water Company	Missouri-American Water Company	Missouri Public Service Commission	WR-2020-0344
2020	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Intermountain Gas Company	Intermountain Gas Company	Idaho Public Utilities Commission	Case No. INT-21-01
2021	Midwestern Gas Transmission Company	Midwestern Gas Transmission Company	Federal Energy Regulatory Commission	RP21-525-000
2021	Enbridge Lakehead System	Enbridge Lakehead System	Federal Energy Regulatory Commission	DO21-15-000
2021	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066
2022	United Illuminating Company	United Illuminating Company	Connecticut Public Utilities Regulatory Authority	22-08-08
2022	Montana-Dakota Utilities	Montana-Dakota Utilities	North Dakota Utilities Commission	Case No. PU-22-194
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0130
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0155

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2022	Northern Natural Gas Company	Northern Natural Gas Company	Federal Energy Regulatory Commission	RP22-1033-0000
2023	Indiana American Water Company	Indiana American Water Company	Indiana Utility Regulatory Commission	Cause No. 45870
2023	Montana-Dakota Utilities	Montana-Dakota Utilities	Public Service Commission of the State of Montana	2022.11.099
2023	Montana-Dakota Utilities	Montana-Dakota Utilities	South Dakota Public Utilities Commission	NG23

EVIDENCE ENTERED INTO PROCEEDINGS IN CANADA

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
1999	ENMAX Power Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2001	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2003	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1279345
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric-ISO Issues	Alberta Energy and Utilities Board	N/A
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Energy and Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	City of Red Deer	City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2008	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1553052
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2010	Enbridge Pipelines Limited· Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1606895
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822
2011	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	lntraGaz Incorporated	lntraGaz Incorporated	La Regie de L'Energie	R-3807-2012

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 3524
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407
2015	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	N/A
2015	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2015	GazMetro	GazMetro	La Regie de L'Energie	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272
2017	NALCOR	NALCOR	Newfoundland Public Utilities Board	Settled
2017	TransCanada Pipelines Limited – Mainline Facilities	TransCanada Pipelines Limited – Mainline Facilities	National Energy Board of Canada	RH-1-2018
2017	TransCanada Pipelines Limited – NGTL Facilities	TransCanada Pipelines Limited – NGTL Facilities	National Energy Board of Canada	RH-001-2019
2018	WestCoast Transmission System	WestCoast Transmission System	National Energy Board of Canada	Settled
2018	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 24195
2018	ATCO Gas	ATCO Gas	Alberta Utilities Commission	Proceeding 24188
2018	SaskEnergy Inc.	SaskEnergy Inc.	Saskatchewan Review Board	N/A
2018	SaskPower	SaskPower	Saskatchewan Review Board	N/A
2018	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	Proceeding 24161
2018	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 23848

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2018	FortisBC Energy Inc.	FortisBC Energy Inc.	British Columbia Utilities Commission	N/A
2018	FortisBC Inc.	FortisBC Inc.	British Columbia Utilities Commission	N/A
2019	Capital Power Corporation	Capital Power Corporation	Municipal Government Board of Alberta	N/A
2019	TransAlta Corporation	TransAlta Corporation	Municipal Government Board of Alberta	N/A
2019	Trans Mountain Pipeline ULC	Trans Mountain Pipeline ULC	Canadian Energy Regulator	T260-2019-04-01
2019	NB Power	NB Power	New Brunswick Energy Utility Regulator	Pending
2019	ATCO Electric	ATCO Electric Transmission	Alberta Utilities Commission	Proceeding 24964
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059
2022	Enbridge Gas Inc.	Enbridge Gas Inc.	Ontario Energy Board	EB-2022-0200
2022	IntraGaz LP	IntraGaz LP	La Regie de L'Energie	R-4189-2022
2022	BC Hydro	BC Hydro	British Columbia Utilities Commission	Project 1599243
2022	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	Manitoba Hydro 2023/24 & 2024/25 General Rate Application
2023	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	Application No. PNG NE2023 to 2024 RRA

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Direct Testimony and Exhibits

of

Michael J. Adams

Cash Working Capital / Lead-Lag Study

July 15, 2024

TABLE OF CONTENTS

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael J. Adams. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Senior Vice President with Concentric Energy Advisors, Inc. ("Concentric").

Q. PLEASE DESCRIBE CONCENTRIC.

A. Concentric is a management consulting and economic advisory firm focused on the North American energy and water industries. Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As a consultant, my responsibilities include assisting clients in identifying and addressing business issues. My primary areas of focus have been regulatory-, financial- and accounting-related issues.

Q. PLEASE DESCRIBE YOUR EDUCATION.

A. I have an MBA from the University of Illinois – Springfield and a BS in Accounting from Illinois College. I am a member of the American Institute of Certified Public Accountants and the Illinois Society of Certified Public Accountants.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

A. I have over thirty-five years of direct experience in the public utility industry. I have worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the energy industry. I have managed and/or participated in a wide variety of consulting engagements. A statement of my background and qualifications is attached as Exhibit MJA-1.

Q. HAVE YOU EVER TESTIFIED IN A REGULATORY PROCEEDING?

A. Yes. I have provided expert testimony or reports before the Arizona Corporation Commission; Arkansas Public Service Commission; the Connecticut Public Utilities Regulatory Authority, the Federal Energy Regulatory Commission (FERC); the Georgia Public Service Commission; the Hawaii Public Utilities Commission; the Idaho Public Utilities Commission; the Illinois Commerce Commission; the Kentucky Public Service Commission; the Maine Public Utilities Commission; the Maryland Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Missouri Public Service Commission; Montana Public Service Commission, the New Hampshire Public Utilities Commission; the New Mexico Public Regulation Commission; New Jersey Board of Public Utilities; the Oklahoma Corporation Commission; the Ontario Energy Board; the Pennsylvania Public Utility Commission; the South Dakota Public Utilities Commission; the Tennessee Public Utility Commission; the Texas Public Utility Commission; the Virginia State Corporation Commission; and the West Virginia Public Service Commission.

My testimonies typically address issues related to cost of service/revenue requirement, shared services, regulatory policy, accounting and/or cost allocations.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I have been asked by Montana-Dakota Utilities Co. ("MDU" or the "Company") to discuss a lead-lag study that was used to develop cash working capital ("CWC") factors and ultimately to calculate the cash working capital requirements of the Company's gas operations. Discussion of the study follows.

III. Cash Working Capital Requirement and Lead-Lag Study

Q. PLEASE DEFINE WHAT YOU MEAN BY THE PHRASE "CASH WORKING CAPITAL."

A. Cash working capital is the amount of funds required to finance the day-to-day operations of the Company.

Q. ARE YOU SPONSORING AN EXHIBIT IN THIS PROCEEDING RELATED TO YOUR ANALYSIS OF CASH WORKING CAPITAL?

A. Yes. Exhibit MJA-2 has been prepared under my direction and supervision and is accurate and complete to the best of my knowledge and belief. Specifically, the Exhibit shows the Company's revenue lag and expense leads for MDU's Montana gas operations.

Q. FOR WHAT PERIOD WAS THE LEAD-LAG STUDY PERFORMED?

A. The lead-lag study analyzed the Company's cash transactions and invoices for the twelve months ended December 31, 2023. The leads and lags were applied to expense amounts for the Test Year.

Q. HOW SHOULD THE RESULTS OF THE CASH WORKING CAPITAL ANALYSIS BE TREATED FOR RATEMAKING PURPOSES?

A. The cash working capital requirements should be included as part of MDU's rate base for ratemaking purposes. The total amount of cash working capital supported by this study is $1,149,064. The determination of the amount of cash working capital requirement is shown in Adjustment L.

Q. IS THE ANALYSIS OF THE REVENUE LAGS AND EXPENSE LEADS TYPICALLY REFERRED TO AS A LEAD-LAG STUDY?

A. Yes. Cash working capital requirements are generally determined by lead-lag studies that are used to analyze the lag time between the date customers receive service and the date that customers' payments are available to the Company. This lag is offset by a lead time during which the Company receives goods and services but pays for them at a later date. The "leads" and "lags" are both measured in days. The dollar-weighted lead and lag days are then divided by 365 to determine a daily CWC factor. This CWC factor is then multiplied by the annual test year cash expenses to determine the amount of cash working capital required for operations. The resulting amount of cash working capital is included as part of the Company's rate base. The test year operating expenses to which the leads and lags were applied in this proceeding are described in the testimony of Company witness Vesey.

Q. WHAT ARE THE VARIOUS LEADS AND LAGS THAT WERE CONSIDERED IN THE CASH WORKING CAPITAL ANALYSIS?

A. Two broad categories of leads and lags were considered: 1) lags associated with the collection of revenues owed to the Company ("revenue lags"); and 2) lead times associated with the payments for goods and services received by the Company, as well as the various taxes and other expenses paid by the Company ("expense leads").

Q. WHAT IS A REVENUE LAG?

A. A revenue lag refers to the elapsed time between the delivery of the Company's product (i.e., gas or electricity) and its ability to use the funds received as payment for the delivery of the product.

Q. WHAT IS AN EXPENSE LEAD?

A. The expense lead refers to the elapsed time from when a good or service is provided to the Company to the point in time when the Company pays for the good or service and the funds are no longer available to the Company.

Q. WHAT WAS THE SOURCE OF INFORMATION YOU EMPLOYED TO DETERMINE THE LEADS AND LAGS IN YOUR CASH WORKING CAPITAL ANALYSIS?

A. Information from the Company was utilized, including data from their Accounts Payable, Customer Service, Human Resources, Payroll, and Tax systems. The information derived from these sources, together with analyses of specific transactions, led to the determination of the appropriate number of lead-lag days for MDU.

A. Revenue Lag

Q. WHAT IS THE REVENUE LAG AND HOW WAS IT DETERMINED?

A. The revenue lag measures the number of days from the date service was rendered by the Company until the date payment was received from customers and such funds were deposited and available to the Company. In the calculation, the revenue lag was divided into five distinct components: 1) service lag; 2) billing lag; 3) collections lag; 4) payment processing lag; and 5) bank float. An explanation of each component of the revenue lag follows.

Q. WHAT IS MEANT BY SERVICE LAG?

A. The service lag refers to the number of days from the mid-point of the service period to the meter reading date for the service period. Using the mid-point methodology, the average lag associated with the provisioning of service was 15.21 days (i.e., 365 days in the year divided by 12 months divided by 2).

Q. WHAT IS MEANT BY BILLING LAG?

A. The billing lag refers to the average number of days from the date on which the meter was read until the customer was billed. The billing lag was determined by analyzing the Company's monthly billing schedules and meter reading records. The average billing lag was determined to be 1.05 days.

Q. WHAT IS MEANT BY COLLECTION LAG?

A. The collection lag refers to the average amount of time from the date when the customers receive a bill to the date that the Company received payment from its customers. For purposes of the cash working capital analyses, the Company's actual customer receivables during the twelve months ended December 31, 2023 were analyzed to determine the collections lag. Based on weighted average data from the Company and considering accounts receivable balances by days aged, the average collection lag was determined to be 42.10 days.

Q. EXPLAIN THE COMPANY'S CALCULATION OF THE COLLECTION LAG.

A. The Company's monthly accounts receivable data was categorized into aging "buckets" of 0-30 days, 31-60 days, 61-90 days, 91-120 days and 120+ days. For purposes of calculating the collection lag, it was assumed that the customers pay their bills ratably over the month. Therefore, the midpoint of the first month is 15 days (*i.e.*, 30 divided by 2). The same assumption that customers will pay their bills ratably over the course of the month was applied to each aging bucket. As such, it was assumed that the Company's customers will pay their bills ratably over the course of the second month (the month that is 31-60 days after the bill was issued). Therefore, the midpoint of payments that are received 31-60 days after the bill is issued is 45 days (*i.e.*, 30 days outstanding from the first month plus the 15-day midpoint of the second month = 45 days). This same theory applies to the use of 75 days for payments that are received 60-90 days after the bill was issued as well as the use of 105 days for the 90-120 days period. Receivables outstanding for 120 days or longer were capped at 121 days. The accounts receivable dollars in each bucket are then multiplied by the midpoint of each bucket to calculate the collection lag.

Q. WHAT IS MEANT BY THE PAYMENT PROCESSING LAG?

A. The payment processing lag refers to the elapsed period of time from the Company's receipt of the customers' funds until the point in time when the customer's payment have been processed and sent to the Company's bank for deposit. The payment processing lag, which was determined based upon an analysis of the various methods of payments used by the Company's customers to pay their bills, and the availability of such funds from each method of payment, was determined to be 0.39 days.

Q. WHAT DOES BANK FLOAT REPRESENT?

A. Bank float represents the elapsed time from when customers' payments via the various methods of payment are deposited at the bank to the time when such funds are available to the Company. Based upon an analysis of the availability of deposited funds in 2023, the bank float was determined to be 0.91 days.

Q. PLEASE SUMMARIZE THE CALCULATION OF BASE REVENUE LAG DAYS.

A. The overall base revenue lag, by lag component, is summarized in the following table.

Revenue Lag by Component	
Service Lag	15.21
Billing Lag	1.05
Collection Lag	42.10
Payment Processing	0.39
Bank Float	0.91
Total Lag (amounts may not add due to rounding)	**59.65**

B. Expense Leads

Q. WHAT EXPENSE-RELATED LEADS WERE CONSIDERED IN THE LEAD-LAG STUDY?

A. Lead times associated with the following expense categories were considered in the lead-lag study: a) payroll and withholdings; b) payroll taxes; c) employee benefits; d) other

O&M; e) gas costs; f) general taxes other than income taxes; g) federal income taxes; h) state income taxes; i) interest on long-term debt; and j) short-term on commercial paper, notes payable and commitment fees.

Q. PROVIDE AN EXPLANATION OF THE EXPENSE LEADS ASSOCIATED WITH THE COMPANY'S PAYROLL AND WITHHOLDINGS EXPENSES.

A. Considering MDU's various payroll periods (i.e. bi-weekly, monthly, and interim payrolls), as well as incentive compensation payments and payroll related withholding payments, the payroll and withholdings expense lead was determined to be 24.08 days.

Q. WHAT PAYROLL RELATED TAXES DOES THE COMPANY PAY?

A. The Company pays the following payroll-related taxes: (1) Federal Unemployment; (2) State Unemployment (Arizona, Idaho, Maryland, Montana, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Washington, and Wyoming); (3) Oregon Workers Benefit Fund; (4) Workers Compensation (North Dakota, Washington, Wyoming); and (5) FICA and Medicare match. The dollar-weighted expense lead for all of these taxes was determined to be 24.35 days.

Q. WHAT EMPLOYEE BENEFITS DOES THE COMPANY PROVIDE AND WHAT IS THE EXPENSE LEAD ASSOCIATED WITH SUCH BENEFITS?

A. The Company provides benefits associated with medical, dental, life, long-term disability insurance as well as health savings accounts, employee assistance programs and 401(k) matching. The dollar-weighted expense lead for these employee benefits was determined to be 13.70 days.

Q. WHAT ARE "OTHER O&M EXPENSES" AND WHAT LEAD TIME WAS ASSOCIATED WITH SUCH EXPENSES?

A. The Company engages in transactions with various vendors for a variety of purposes including facility maintenance, system maintenance, and customer service. Accounts payable data was analyzed in order to calculate a lead time associated with payments for services related to other operations and maintenance activities. The analysis indicates that on average, invoices were paid by the Company 36.02 days after receipt. This lead time includes a service lead time.

Q. WHAT IS THE EXPENSE LEAD TIME ASSOCIATED WITH THE COMPANY'S FUEL EXPENSES?

A. The Company purchases natural gas for distribution to its gas customers. Based on an examination of the service periods and payment dates for the Company's purchases of natural gas, a weighted expense lead time of 39.38 days was determined.

Q. WHAT ARE THE VARIOUS GENERAL TAXES CONSIDERED IN THE ANALYSIS?

A. The following general taxes were considered in the study: a) Property Tax; b) Montana Consumer Counsel Tax; c) Montana Public Service Commission Tax; d) Montana Secretary of State Tax; e) Highway Use Tax; and f) Delaware Franchise Fee.

Q. EXPLAIN THE LEAD EFFECTS ASSOCIATED WITH EACH TYPE OF GENERAL TAXES CONSIDERED IN THE ANALYSIS.

A. The treatment of each category of general taxes in the study is described below:

a) Property Tax: Taking the semi-annual periods for which the tax is assessed, as well as the timing of the statutory due date and amounts into consideration for the property tax payments, a dollar-weighted expense lead of 252.35 days was determined.

b) Montana Consumer Counsel Tax: Taking the quarterly period for which the tax is assessed, as well as the timing of the statutory due date and the amount into consideration for the property tax payments, a dollar-weighted expense lead of 75.52 days was determined.

c) Montana Public Service Commission Tax: Taking the quarterly periods for which the tax is assessed, as well as the timing of the actual payment dates and amounts into consideration for the Public Service Commission Tax payments, a dollar-weighted expense lead of 75.52 days was determined.

d) Montana Secretary of State Tax: If a company has received authority to do business in the State, the Secretary of State's Office requires an annual or biennial report to be filed by the company to keep the company in "good standing." If these reports are not filed, the company's authority to do business in Montana will be revoked. The dollar-weighted expense lead associated with the Secretary of State Tax was calculated to be negative 77.50 days.

e) Highway Use Tax: The IRS Form 2290, heavy highway vehicle use tax return is the tax on highway motor vehicles used during the tax period. Taking the annual period for which the tax is assessed, as well as the timing of the actual payment date and amount into consideration for the tax payment, a dollar-weighted expense lead of negative 122.0 days was determined.

f) Delaware Franchise Fee: Montana-Dakota Utilities Co. was incorporated in the State of Delaware, so this is a franchise fee which is due each year. The tax is based on authorized shares. Based upon the due dates, the expense lead associated with the Delaware Franchise Fee Tax was calculated to be 107.3 days.

Q. HOW DID YOUR STUDY ADDRESS FEDERAL INCOME TAXES?

A. The lead time associated with federal income tax payments was based on the provisions of the Internal Revenue Code that require estimated tax payments of 25 percent of total income taxes due each quarter of the current year. Taking this schedule into consideration a lead time of 37.88 days for federal income taxes was determined.

Q. HOW DID YOUR STUDY ADDRESS STATE INCOME TAXES?

A. The Company makes quarterly payments to the state. Taking this statutory payment schedule into consideration, an expense lead time of 37.88 days for state income tax payments was determined. Since payments are made electronically, no additional float time was included.

Q. PROVIDE A DESCRIPTION OF HOW LEAD TIMES ASSOCIATED WITH THE COMPANY'S LONG-TERM INTEREST EXPENSES WERE ADDRESSED BY THE STUDY.

A. The Company made semi-annual interest payments on its long-term debt throughout the test year. Using the midpoints of the semi-annual service periods, a dollar-weighted lead of 90.93 days for long-term interest payments was determined.

Q. DID YOU ALSO CALCULATE THE LEAD TIMES ASSOCIATED WITH THE COMPANY'S SHORT-TERM INTEREST EXPENSE?

A. Yes. The Company made periodic interest payments on three different types of short-term debt throughout the test year. The debt instruments included: 1) term loan commercial paper; 2) a Montana Air Force Base ("MAFB") note payable associated with the purchase of the Base; and 3) commitment fees paid associated with short-term debt. Using the midpoints of the service periods, a combined dollar-weighted lead of 17.16 days for short-term interest payments was determined.

Q. BASED UPON THE RESULTS OF THE LEAD-LAG STUDY AND THE LEVEL OF EXPENSES SPONSORED BY COMPANY WITNESS VESEY, WHAT LEVEL OF CASH WORKING CAPITAL REQUIREMENTS SHOULD BE INCLUDED IN MDU'S RATE BASE?

A. As shown in Adjustment L, a cash working capital requirement of $1,149,064 should be included in the Company's rate base.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ *Michael J. Adams*

Michael J. Adams
Senior Vice President
Concentric Energy Advisors, Inc.

MICHAEL J. ADAMS
SENIOR VICE PRESIDENT

Mr. Adams has over thirty-five years of direct experience in the public utility industry. He has worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the utility industry.

While employed by Illinois Power Company, Mr. Adams monitored project expenditures associated with gas and electric distribution, transmission, and generation capital projects.

While employed by the Illinois Commerce Commission, Mr. Adams initially evaluated the rate filings of regulated utilities and provided expert testimony regarding the reasonableness of the requests. Mr. Adams was subsequently charged with developing and managing a management and operations audit program to evaluate company management policies, procedures, and performance, as well as operational efficiency and effectiveness. Mr. Adams served as the Deputy Executive Director of the agency at the time of his departure. As a consultant, Mr. Adams has provided consulting services to regulatory agencies and regulated utilities on an array of operational and financial issues since 1995.

Prior to joining Concentric, Mr. Adams was a Managing Director of Navigant Consulting, Inc. Mr. Adams is a Certified Public Accountant, a graduate of Illinois College and holds an M.B.A. from the University of Illinois, Springfield.

Mr. Adams provides financial, regulatory, strategic, operational and litigation support to his energy clients. He has assisted clients with regulatory/legislative initiatives related to the approval and implementation of alternative regulation plans as well as the preparation and support of regulatory filings under alternative rate plans. Mr. Adams also provides advisory services in the areas of mergers and acquisitions. As a consultant, Mr. Adams has provided expert testimony or reports before State and Federal regulatory agencies.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc.
Senior Vice President
Vice President

Navigant Consulting, Inc.
Managing Director

L.E. Burgess Consultants, Inc.

Illinois Commerce Commission
Accounting/Rate Case Staff
Director, Management Audit/Studies
Deputy Executive Director

Illinois Power Company
Accounting/Auditing Department

EDUCATION

University of Illinois at Springfield
M.B.A., Finance

Illinois College
B.S., Accounting

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant
American Institute of Public Accountants
Illinois Society of Certified Public Accountants

REPRESENTATIVE PROJECT EXPERIENCE

AUDITS/SPECIAL STUDIES

- Management audits
- Regulatory reviews/audits
- Project performance monitoring/reviews
- Prudence reviews
- Commission ordered studies
- Audit prep and support
- Project controls and assessments

AFFILIATE TRANSACTIONS

- Code of Conduct
- Shared Services reviews
- Cost controls

BENCHMARKING

- O&M costs
- Capital expenditures
- Shared Services
- Operational performance
- Customer service

- Reliability

DUE DILIGENCE/LITIGATION/SPECIAL PROJECTS

- Assessment of cost controls
- Financial outlook
- Historical/future performance assessment
- Merger Synergies
- Regulatory environment/assessment

EXPERT WITNESS

- Regulatory proceedings
- Civil litigation

LITIGATION SUPPORT

- Data review and analyses
- Position development and review
- Research
- Expert testimony and reports

REGULATORY PROCEEDINGS

- Revenue Requirement
- Cash working capital
- Benchmarking
    - O&M
    - Capital
    - Shared Services
- Case development/management
- Multi-year rate plans
- Research
- Performance based regulation

EXPERT TESTIMONY OF MICHAEL J. ADAMS				
SPONSOR	YEAR	CASE/APPLICANT	DOCKET NO.	SUBJECT
Arizona Corporation Commission				
Liberty Utilities (Entrada Del Oro Sewer Company and Gold Canyon Sewer Company	2022	Liberty Utilities	SW-02519A-0235, SW-0362+A-21-0236, SW-04316A-21-0359	Indirect Overhead/Capitalization Rates
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	2002	Arkansas Oklahoma Gas Corporation	02-024-U	Reasonableness of ratemaking adjustments
CenterPoint Energy Arkla	2005	CenterPoint Energy Arkla	04-121-U	Cash Working Capital
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas	2013	Connecticut Natural Gas	13-06-08	Cash Working Capital
Connecticut Natural Gas	2023	Connecticut Natural Gas	23-11-02	Cash Working Capital
Southern Connecticut Gas Company	2023	Southern Connecticut Gas Company	23-11-02	Cash Working Capital
United Illuminating Company	2022	United Illuminating Company	22-08-08	Cash Working Capital
Federal Energy Regulatory Commission				
Granite State Gas Transmission	2010	Granite State Gas Transmission	RP10-896	Revenue Requirement
Georgia Public Service Commission				
Atlanta Gas Light Company	2019	Granite State Gas Transmission	42315	Cash Working Capital
Hawaii Public Utilities Commission				
Hawaii Electric Light Company, Inc.	2005	Hawaii Electric Light Company, Inc.	05-0315	Allowance for Funds Used During Construction
Idaho Public Utilities Commission				
Intermountain Gas Company	2016	Intermountain Gas Company	INT-G-16-2	Cash working capital, prepared/supported benchmarking for client

Illinois Commerce Commission				
Illinois Power Company	1999	Illinois Power Company	99-0120/99-0134 (Cons.)	Functionalization/ Unbundling of General and Intangible Assets and Administrative and General expenses.
Illinois Power Company	2004	Illinois Power Company	04-0476	Cash working capital and asset separation
Ameren Illinois Utilities	2006	Ameren Illinois Utilities	06-0070/06-0071/06-0072 (Cons.)	Functionalization of Assets, Cash Working Capital, Shared Services Costs, Benchmarking
Ameren Illinois Utilities	2007	Ameren Illinois Utilities	07-0585/07-0586/07-0587/ 07-0588/07-0589/07-0590 (Cons.)	Shared Services Costs, Asset Separation, Cash Working Capital
The Peoples Gas Light and Coke Company, Inc., and North Shore Gas Company	2007	The Peoples Gas Light and Coke Company, Inc., and North Shore Gas Company	07-0241/07-0242 (Cons.)	Cash working capital
Northern Illinois Gas Company	2008	Northern Illinois Gas Company	08-0363	Cash working capital
Ameren Illinois	2015	Ameren Illinois	16-0262	Benchmarking of Utility Performance
Commonwealth Edison Company	2022	Commonwealth Edison Company	22-0645	Rider ZEA Reconciliation
Commonwealth Edison Company	2022	Commonwealth Edison Company	22-0103	Rider PE Reconciliation
Nicor Gas	2023	Nicor Gas	23-0066	Cash working capital
Commonwealth Edison Company	2023	Commonwealth Edison Company	22-0486; 23-0055 (cons).	Cash working capital
Commonwealth Edison Company	2023	Commonwealth Edison Company	23-0064	Rider PE Reconciliation
Ameren Illinois	2023	Ameren Illinois	22-0487/ 23-0082	Assessment of MYRP
Kentucky Public Service Commission				
Kentucky Power Company	2023	Kentucky Power Company	2023-00159	Cash working capital

Maine Public Utilities Commission				
Emera Maine	2017	Emera Maine	Docket No. 2017-00198	Cash working capital
Versant Power	2020	Versant Power	Docket No. 2020-00316	Cash working capital
Versant Power	2022	Versant Power	Docket No. 2022-00255	Cash working capital
Maryland Public Service Commission				
Constellation Energy	2009	Constellation Energy	Case No. 9173, Phase II	Shared Services, Benchmarking
Massachusetts Department of Public Utilities				
Massachusetts Distribution Companies	2002	Massachusetts Distribution Companies	DTE-99-84	Reliability standards and the appropriateness of utilizing data for benchmarking purposes
Missouri Public Service Commission				
AmerenUE (Union Electric Company)	2002	AmerenUE (Union Electric Company)	EC-2002-001	Cash working capital
AmerenUE	2003	AmerenUE	GR-2003-0517	Cash working capital
AmerenUE	2007	AmerenUE	ER-2007-0002	Cash working capital
AmerenUE	2008	AmerenUE	ER-2008-0318	Cash working capital
Missouri Gas Energy	2006	Missouri Gas Energy	GR-2006-0422	Cash working capital
Ameren Missouri Gas	2010	Ameren Missouri Gas	GR-2010-0363	Cash working capital
Ameren Missouri Electric	2010	Ameren Missouri Electric	ER-2011-0028	Cash working capital
Ameren Missouri	2012	Ameren Missouri	ER-2012-0166	Cash working capital
Ameren Missouri	2014	Ameren Missouri	ER-2014-0258	Affiliate transactions, Benchmarking
Evergy Metro, Inc.	2022	Evergy Metro, Inc.	ER-2022-0129	Cash working capital, Property Tax Tracker
Evergy Missouri West, Inc.	2022	Evergy Missouri West, Inc.	ER-2022-0130	Cash working capital, Property Tax Tracker
Montana Public Service Commission				
Montana-Dakota Utilities	2022	Montana-Dakota Utilities	EL -12-020	Cash working capital
Montana-Dakota Utilities	2022	Montana-Dakota Utilities	NG-23-014	Cash working capital

Montana-Dakota Utilities Co.	2024	Montana-Dakota Utilities		Cash working capital
New Hampshire Public Utilities Commission				
National Grid Energy North	2010	National Grid Energy North	DG 10-017	Revenue Requirement
New Mexico Public Regulation Commission				
New Mexico Gas Company	2019	New Mexico Gas Company	No. 19-00317-UT	Future Test Year Model / Revenue Requirement
New Jersey Board of Public Utilities				
PSEG	2018	PSEG	ER18010029 & GR18010030	Benchmarking and Cash Working Capital
PSEG	2023	PSEG		Benchmarking and Cash Working Capital
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	2003	Arkansas Oklahoma Gas Corporation	PUD200300088	Cash working capital
Ontario Energy Board				
Hydro One Distribution Business	2005	Hydro One Distribution Business	-	Cash working capital
Hydro One Transmission Business	2006	Hydro One Transmission Business	-	Cash working capital
Toronto Hydro	2006	Toronto Hydro	-	Cash working capital
Pennsylvania Public Utility Commission				
Allegheny Power	2004	Allegheny Power	M-00991220	Reliability data and reasonableness of established standards
T.W. Phillips Gas and Oil Company, Inc.	2006	T.W. Phillips Gas and Oil Company, Inc.	R-00051178	Cash working capital
South Dakota Public Utilities Commission				
Montana-Dakota Utilities	2023	Montana-Dakota Utilities	D-EL23-020 E-NG23-014	Cash working capital
Tennessee Public Utility Commission				
Chattanooga Gas Company	2018	Chattanooga Gas Company	18-00017	Cash working capital
Texas Public Utility Commission				
Texas-New Mexico Power Company	2008	Texas-New Mexico Power Company	36025	Revenue Requirement

El Paso Electric Company	2012	El Paso Electric Company	40094	O&M Benchmarking
El Paso Electric Company	2014	El Paso Electric Company	-	Benchmarking of New Generation Costs
El Paso Electric Company	2015	El Paso Electric Company	44941	Benchmarking of costs of new generation units
Virginia State Corporation Commission				
Virginia Natural Gas	2012	Virginia Natural Gas	PUE-2010-00142	Cash Working Capital
Virginia Natural Gas	2017	Virginia Natural Gas		Shared Services Review, Benchmarking, Cash Working Capital
Virginia Natural Gas	2022	Virginia Natural Gas	PUR-2022-00052	Cash working capital
West Virginia Public Service Commission				
Appalachian Power Company	2018	Appalachian Power Company	18-0646-E-42T	Cash working capital

Montana-Dakota Utilities

Cash Working Capital Leads/Lags

Line No.	Lead/Lag	Days
1	**Revenue Lag**	
2	Service Lag	15.21
3	Billing Lag	1.05
4	Bank Float	0.91
5	Payment Processing	0.39
6	Collections Lag	42.10
5	Total Revenue Lag	59.65
6	**Expense Leads**	
7	Payroll and Withholdings	24.08
8	Payroll Taxes	24.35
9	Employee Benefits	13.70
10	Other O&M Expenses	36.02
11	Gas Costs	39.38
12	Property Taxes	252.35
13	Delaware Franchise Fee	107.30
14	Highway Use Tax	-122.00
15	Secretary of State	-77.50
16	Consumer Counsel Tax	75.52
17	Public Service Commission Tax	75.52
18	Federal Income Taxes	37.88
19	State Income Taxes	37.88
19	Interest on Long-Term Debt	90.93
20	Term Loan	17.16

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2024.05.061

Direct Testimony

Of

Nathan A. Bensen

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

A. Yes. My name is Nathan A. Bensen, 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 Senior Regulatory Analyst in the Regulatory Affairs Department for Montana-Dakota Utilities Co. (Montana-Dakota).

Q. Would you please describe your duties as a Regulatory Analyst?

A. I assist in the preparation of the annual electric rider filings in North Dakota and South Dakota, weather normalization of natural gas volumes, and other filings required by state commissions.

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

A. I graduated from the University of North Dakota with a Bachelor of Accountancy degree. I have been in my current position with Montana-Dakota for seven years. Prior to starting in my current role June of 2017, I was employed by the State of North Dakota as an Auditor for sales, use and gross receipts taxes with the Office of the Tax Commissioner; and a Cost Report Auditor with the Department of Health and Human Services.

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

A. Yes. I have previously prepared testimony for the North Dakota Public Service Commission and have presented testimony to the South Dakota Public Utilities Commission.

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

A. The purpose of my testimony is to present the methodology used by Montana-Dakota to forecast natural gas sales data, including weather normalized volumes, pro forma volumes and pro forma customers. The totality of this process and its results are the foundational basis for the underlying pro forma revenues used in this rate case.

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

A. I am sponsoring the development of the projected billing units as presented on Exhibit No. ___(NAB-1) and ultimately used in the projected revenues on Statement H, pages 1 through 23. The results presented on Exhibit No. ___(NAB-1) are supported by the regression results included in Workpapers Statement H, pages 2 through 39.

Q. Would you describe the development of the normalized volumes?

A. Natural gas volumes for residential, firm general, and select interruptible and transportation customers were adjusted to reflect normal weather patterns, where appropriate. Each of the aforementioned customer classes were adjusted separately. Billing period sales volumes and customers, by month, were the starting point for the data utilized in the models.

First, customer classes were analyzed, with input from the Company's Gas Supply Department, to determine whether natural gas usage was associated with heating purposes and therefore correlated with weather. 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 regression model 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.

Using the results of the regression analysis for residential and firm general service customer classes, the daily baseload use per customer 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 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. Montana-Dakota has historically used 30-year normals for weather normalization purposes and believes that using 30-years of normal weather data continues to be 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, 2023.

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 two or three year average was calculated based on actual use during the period of January 2021 – December 2023.

Q. Was any consideration given to customers which changed rate classes?

A. Yes. Montana-Dakota 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 2021 through 2023, 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. There were no known customers changing classes at the time of the preparation and finalization of the normalized and projected volumes.

Q. How were the pro forma volumes calculated for heat-sensitive customers?

A. The pro forma volumes were based upon the calculated normalized volumes for each customer class. For the residential and firm general rate classes, Montana-Dakota utilized an annualization process to obtain a pro forma level of customers and volumes. The annualization process allows for Montana-Dakota to account for customer growth within 2023 and reflect volumes had these new customers been in service for the entire calendar year of 2023. For other heat-sensitive customers and classes, the pro forma volumes were set equal to the normalized volumes as calculated and described previously.

Q. How were the pro forma volumes calculated for non-heat sensitive customers?

A. The pro forma volumes for the non-heat sensitive customers were set equal to their normalized volumes.

Q. Would you describe the weather data utilized in developing weather normalized gas sales?

A. Montana-Dakota purchases raw daily weather data from DTN. The data utilized in the weather normalizations is the average temperature in degrees Fahrenheit for areas that Montana-Dakota provides natural gas service in Montana. 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 four regional weather stations in Montana (Billings, Glasgow, Glendive and Miles City) and the differences for each day are considered calendar degree days. 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 four regions. These regional BPDDs are then weighted based upon the historical number of firm customer service points to calculate a system-wide Montana BPDD.

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. Microsoft Excel's Distinct Count function was used to count the number of unique customers. The Count function 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 function has been utilized by Montana-Dakota to determine its customer counts in rate cases filed in Montana and other jurisdictions as it accounts for adjustments and corrections to customer bills in the CC&B data set.

Q. Does this complete your direct testimony?

A. Yes, it does.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ Nathan A. Bensen

Nathan A. Bensen
Senior Regulatory Analyst

Montana-Dakota Utilities Co.
Gas Utility - Montana
Normalization Summary
For the Twelve Months Ending December 31, 2023

	Per Books Customers	Normalized	Annualized	Per Books Volumes		Normalized	Annualized
Rate 60 - Residential	78,207	78,207	78,431	6,229,315.1		6,094,672	6,115,799
Rate 70 - Small Firm General	7,972	7,972	8,071	1,162,570.3		1,137,684	1,155,239
Rate 70 - Large Firm Sales:							
Rate 70 - Large Firm General	2,668	2,668	2,678	2,980,262.1	1/	2,891,098	2,904,245
Rate 70 - First Through Meter	16	16	16	94,769.3		84,899	84,899
Total Rate 70 - Large:	2,684	2,684	2,694	3,075,031.4		2,975,997	2,989,144
Rate 72 - Optional Seasonal	6	6	6	12,576.9		11,818	11,818
Rate 74 - Contract Demand 2/							
Rate 74 - Small Service	3	3	3	1.1		1	1
Rate 74 - Large Service	9	11	11	76.3		104	104
Total Rate 74:	12	14	14	77.4		105	105
Total Firm Service:	**88,881**	**88,883**	**89,216**	**10,479,571.1**		**10,220,276**	**10,272,105**
Rate 71 - Small IT Sales:	19	19	19	358,790.8		230,122	230,122
Rate 81 - Small IT Transport:	27	27	27	592,580.7		568,962	568,962
Rate 81 - Contract Cust 81-11:	0	0	0	632.0		0	0
Total Rate 81:	27	27	27	593,212.7		568,962	568,962
Rate 82 - Large IT Transport:	1	1	1	181,447.4		226,343	226,343
Rate 82 - Contract Cust 82-2:	1	1	1	159,176.8		113,319	113,319
Rate 82 - Contract Cust 82-3:	1	1	1	2,323,704.7		2,557,556	2,557,556
Rate 82 - Contract Cust 82-4:	1	0	0	173,424.7		0	0
Total Rate 82:	4	3	3	2,837,753.6		2,897,218	2,897,218
Rate 85 - Large IT Sales	1	1	1	112,254.0		104,045	104,045
Total IT Sales & Transportation:	**51**	**50**	**50**	**3,902,011.1**		**3,800,347**	**3,800,347**
Total Sales:	88,901	88,903	89,236	10,950,615.9		10,554,443	10,606,272
Total Transport:	31	30	30	3,430,966.3		3,466,180	3,466,180
Total Sales & Transport:	**88,932**	**88,933**	**89,266**	**14,381,582.2**		**14,020,623**	**14,072,452**

1/ Per books volumes include 443.4 Dk of unauthorized penalty use volumes. These are excluded from normalized and annualized volumes.

2/ Per books, normalized and annualized Dk represents actual and pro forma use. Rate 74 customers are also charged for contract demand. Contracted Demand Dk is outlined below:

	Per Books	Normalized	Annualized
Rate 74 - Small:	36.0	36.0	36.0
Rate 74 - Large:	775.0	648.0	648.0
	811.0	684.0	684.0

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2024.05.061

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 electric 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 this Commission, the Public Service Commissions of North Dakota 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 Montana gas operations per books cost of service for the twelve months ended December 31, 2023 and the pro forma cost of service reflecting known and measurable adjustments that will occur by December 31, 2024. Based on the results, I have prepared the calculation of the revenue deficiency and the calculation of the interim request. I will also discuss the Company's proposal to include Cash Working Capital Adjustment in rate base. Furthermore, I will present proposed changes to Rate 88 – Gas Cost Tracking Adjustment in this filing.

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

A. I am sponsoring Statements C through E, Statements G through K (excluding Statement H, pages 6 through 23), Part A of Statement O, and the revenue requirement presented in Exhibit No.___ (TRV-1). I am also sponsoring the Interim Statements C through E, Statement G through K, Statement O, and the revenue requirement presented in Exhibit No.___(TRV-2). Finally, I am sponsoring the changes to Rate 88 – Gas Cost Tracking Adjustment presented in Exhibit No. ___(TRV-3).

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

A. Yes, they were.

Case Description

Q. What is the revenue deficiency?

A. The Company has determined a revenue shortfall of $9,392,775, which represents an 11.1 percent increase, based on a pro forma 2024.

Q. How was the $9,392,775 revenue deficiency derived?

The Company has developed the pro forma revenue requirement based on adjustments to the sales revenues, Operation & Maintenance (O&M) expenses, taxes and the December 31, 2023 pro forma rate base. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable.

Pro Forma Revenue Requirement

Q. What were the results of Montana gas operations for the twelve months ended December 31, 2023?

A. Rule 38.5.175, pages 1 and 2 show the per books income statement and rate base for total Company and Montana. As shown on page 1, Montana gas operations had a return on rate base of 2.600 percent for the twelve months ended December 31, 2023. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the applicable Rule listed. Pages 3 and 4 list the pro forma adjustments to operating revenues, expenses and rate base. All adjustments were calculated on either a Montana specific basis or on a total Company basis and allocated to Montana, as indicated on the statement or schedule detailing each adjustment.

Q. How was the per books cost of service allocated to Montana?

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense and rate base to the jurisdictions as part of the regular accounting process on a monthly basis. The allocation methods and procedures are the same as have previously been used in Commission proceedings and are based on the principle of assigning and/or allocating costs to the cost causer.

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

A. The revenue requirement is based on December 31, 2023 test period to create a pro forma year ending December 31, 2024. As stated by Ms. Kivisto, the proposed $9.4 million increase in revenue is largely driven by:

	Amount (in millions)
O&M Expenses	$3.6
Rate Base	2.2
SSIP	1.7
Depreciation	1.4
Other	0.5
Net Increase	$9.4

Montana-Dakota's cost of doing business in Montana is increasing despite the Company's effort to control costs and increase efficiency. The Company is experiencing a $3.6 million increase in O&M expenses due to increased labor, vehicles and work equipment, and software maintenance. Rate base investment since the last case, including System Safety Integrity Program (SSIP) referenced in the testimony of Mr. Jesse Volk, represents $3.9 million of the increase. Finally, increases in depreciation expense, primarily driven by the investment in rate base (and somewhat offset by the implementation of the updated depreciation studies), result in a revenue requirement increase of approximately $1.4 million.

Q. What criteria were used to determine the pro forma adjustments?

A. The pro forma adjustments to operating revenue, expenses and rate base were based on known and measurable changes occurring by December 31, 2023, conformed to past Commission practices and are listed on pages 3 and 4 of Rule 38.5.175. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable.

Q. Would you describe the pro forma adjustments to the income statement and rate base?

A. Yes. The adjustments to the income statement are summarized on Rule 38.5.175, page 3 and consist of adjustments to revenue, operation and maintenance expenses, depreciation expense, taxes other than income, and current and deferred income taxes. The adjustments to rate base are summarized on page 4 and include plant, accumulated reserve for depreciation and associated additions and deductions. Each adjustment is discussed in detail below.

<u>Pro Forma Income Statement</u>

Q. What adjustments were made to operating revenues?

A. The adjustments to operating revenues are contained in Rule 38.5.164, Statement H. Adjustment No. 1, as shown on page 3, restates the per books consumption at current rates, adjusted to reflect an annual gas cost for 2024, exclusive of the surcharge adjustment, and eliminates the unbilled revenue, decreasing revenue by $5,605,862.

Adjustment No. 2, on page 4 of Statement H, decreases revenues by $2,220,483 to reflect the effect of normal weather on sales and transportation volumes. Weather was 2.34 percent colder than normal in 2023. The normalization process and results are fully supported in Mr. Nathan A. Bensen's testimony.

Page 5 shows Adjustment No. 3 is an increase to revenues of $404,374 to reflect the annualization of firm customers to the December 2023 level. More detailed testimony regarding the development of revenue reflected in this case is supported in the Direct Testimony of Ms. Stephanie Bosch.

Adjustment No. 4, on page 24 of Statement H, is comprised of several adjustments to other operating revenues. The pro forma adjustment decreases revenue by $359,752 and consists of several adjustments. They are as follows:

- Seasonal Reconnect Fee, Reconnect Fee for Non-payment, NSF Check Fees, Energy Diversion, Sale of Sundry Junk Material, Patronage Dividends, Meter Reading for Others, and Miscellaneous Revenue were adjusted to reflect a three-year average.
- Rent from Property was updated to reflect actual 2024 activity on an annualized basis, which excluded a one-time payment in 2023;
- Late payment revenue is based on a three-year average ratio of the late payment revenue collected and the sales and transportation revenue, which is then applied to the Pro Forma Revenue;
- Gain/(loss) on Disposal of Property amortized based on sale of plant over five year period.

- Penalty revenue was adjusted based on corrected 2023 amount; and
- Conservation and Tracking Adjustment Revenue was adjusted to reflect expense as shown on Rule 38.5.157, Statement G, page 22.

Q. What adjustments were made to operations and maintenance (O&M) expenses?

A. The adjustments to operation and maintenance expenses are contained in Rule 38.5.157, Statement G, and are summarized in Rule 38.5.156.

The adjustment to the cost of gas (Adjustment No. 5) is shown on Rule 38.5.157, page 3, and adjusts the cost of gas to reflect the pro forma dekatherm (dk) sales and an annual 2024 gas cost level. Adjustment No. 5 includes volume adjustments reflected in Adjustment Nos. 1 through 3 as discussed above. The pro forma cost of gas per dk was derived by calculating annual demand charges based on the March 2024 purchased gas cost adjustment and the 2024 projected commodity cost of gas.

Q. Would you describe the development of labor and benefits expense?

A. Yes. Labor expense is shown as Adjustment No. 6, in Rule 38.5.157, Statement G, page 6. The pro forma labor was developed by applying the percentage of total adjusted per book labor multiplied by the Pro Forma Labor by Object total. Pro forma total Company labor costs were based on the application of an increase of 5.0 percent for union employees and 4.5 percent for nonunion employees effective in 2024 as shown on Statement Workpaper G, page 5. Bonuses and commissions reflect the actual stock compensation, expected miscellaneous expenses and meals for 2023. Pro forma incentive compensation has been adjusted to reflect 11.58% of straight time and vacation, which is considered the incentive compensation target. The per books 2023 short term incentive compensation calculation resulted in a payout over 100% of targeted payout, thus a reduction is reflected in the Pro Forma Labor by Object.

The labor expense pro forma adjustment results in an overall net decrease of $62,462.

Benefits are shown on page 7 of Statement G. Adjustment No. 7 is an overall increase of $190,215 in benefits. Benefits expense consists of medical/dental insurance, pension expense, post-retirement, 401K, workers compensation, and other benefits. Each of these items was adjusted individually using current information and applying the percentage change to each type of benefit.

Medical and dental expense is increasing 8.39 percent to reflect the premiums in effect for 2024 as compared to the 2023 actual results. Actuarial Pension expense increased 92.22 percent and Post-retirement increased by 9.41 percent from 2023 levels. 401K expense, workers compensation and other benefits are tied to labor costs and increase 4.69 percent to reflect the overall average increase in straight time labor.

Q. Would you describe the other adjustments made to O&M expense?

A. Yes. Vehicles and work equipment is shown as Adjustment No. 8, in Rule 38.5.157, Statement G, page 8 reflects all expenses associated with the Company's vehicles and equipment, such as backhoes, skid steers and excavators, including the costs of fuel, insurance, maintenance and depreciation expense. Adjustment No. 8 reflects an increase of $563,796. The depreciation component on these items is not charged to depreciation expense but rather is charged to a clearing account where it is then recorded in O&M expense as the vehicles or work equipment is used. The increase is primarily due to proposed depreciation rate change for Power Operated Equipment.

Company consumption shown in Rule 38.5.157, Adjustment No. 9, Statement G, page 9 is the expense for general utilities, electric and natural gas consumption in Company buildings and is expected to decrease $4,802. The general utilities and electric component is projected to increase 3.57 percent to reflect volumes at current rates. The natural gas component is based on a decrease of 24.53 percent to reflect normalized weather volumes.

Uncollectible accounts, Adjustment No. 10, is a decrease of $16,455 based on the three-year average of net write-offs to pro forma sales and transportation revenues.

Postage expense, Adjustment No. 11, shown on page 11 of Statement G, is an increase of $34,510 and reflects a 12.60% increase in postage costs based on the pro forma weighted average increase that is then partially offset by electronic billing savings for the twelve months ending December 31, 2023.

Adjustment No. 12 for advertising expense is shown on page 12 of Rule 38.5.157, Statement G and reflects a decrease of $48,250. Pursuant to past Commission policy, general promotional and institutional advertising expense has been eliminated. Informational advertising is adjusted to exclude advertising that in not applicable to Montana gas operations.

Adjustment No. 13 for software maintenance expense is an increase of $70,569 and is based on pro forma levels.

Insurance expense is shown on Adjustment No. 14 reflects an increase of $34,343. This increase is adjusted to reflect anticipated 2024 expenses and a 5-year average of self-insurance expense.

Adjustment No. 15 for industry dues reflects the pro forma level of industry dues and is a decrease of $6,462. Rule 38.5.157, Statement G, page 15 through 17 shows those dues that are directly assigned or allocated to Montana, the appropriate pro forma expense level and the benefit to the ratepayer. For those organizations that provide lobbying services, Montana-Dakota records the lobbying expenses below the line and thus are not included in this adjustment. Furthermore, in compliance with past Orders, 40 percent of dues to the local Chambers of Commerce are excluded.

Regulatory commission expense shown as Adjustment No. 16 on page 18 of Rule 38.5.157, Statement G, reflects the expenses to be incurred in this filing and the expenses related to depreciation studies, amortized over a five-year period, and a three-year average of ongoing regulatory commission expenses. The adjustment is an increase of $171,020.

Materials expense shown as Adjustment No. 17, on page 19 is an increase of $73,054 and is adjusted to reflect an increase in normal materials expense.

Adjustment No. 18 showing Subcontract Labor expense in Rule 38.5.157, Statement G, page 20 is based on the Pro Forma adjusted value to reflect the decrease of $7,575.

Rent Expense shown as Adjustment No. 19, on page 21 of Rule 38.5.157, Statement G, reflects the adjusted decrease of $110,698 in rent. The projected 2024 reflects adjustments for increases in Distribution due to the radio tower leases. Customer accounting was adjusted due to return of rental equipment mid-year and A&G was adjusted for 2024 based off a lower depreciation expense due to information technology assets fully depreciating in 2024.

Adjustment No. 20 showing Conservation Tracking Adjustment on page 22 of Rule 38.5.157, Statement G reflects Pro Forma CTA expense to remain at current level and to match revenue as shown on Rule 38.5.164, Statement H, page 24.

The items adjusted individually above represent approximately 98.4 percent of total Montana gas O&M. The remaining items, which make up approximately 1.6 percent of other O&M, are assumed to remain flat.

Q. Would you describe the calculation of depreciation expense?

A. Yes. The adjustment to depreciation expense is contained in Rule 38.5.165, Statement I. Adjustment No. 20, as found on pages 1 through 8, restates the annual depreciation expense to the average pro forma level of plant in service resulting in an increase of $9,040. Concentric Advisors, ULC prepared gas and common plant depreciation studies, at the Company's request, for gas and common assets based on the plant balances on December 31, 2021. The depreciation studies are supported in the testimony of Mr. Larry E. Kennedy.

Q. What adjustments were made to taxes other than income?

A. The adjustments to taxes other than income are contained in Rule 38.5.174, Statement K. Adjustment No. 21 is shown on page 1 and updates Montana direct ad valorem taxes. This adjustment reflects a slight increase based on the three-year average of the year over year change in ad valorem taxes as shown on Workpaper Statement K, page 1. Adjustment No. 21 also restates ad valorem taxes allocated from North Dakota to the average allocated pro forma plant balances based on the average increase of 6.66% over the last three years. The net result is an increase of $27,490, of which Montana direct ad valorem taxes account for $25,257.

Adjustment No. 22 on page 2 of Rule 38.5.174, Statement K, shows payroll taxes reflecting a decrease of $4,547 based on the ratio of payroll taxes to labor expense for 2023 applied to pro forma labor expense.

The Montana Consumer Counsel Tax and Public Service Commission taxes are restated in Adjustment No. 23 on page 3 of Rule 38.5.174, Statement K, to the pro forma level of revenue and the rates effective October 1, 2023 and results in an increase of $38,019.

Q. **What adjustments were made to income taxes?**

A. The adjustments to income taxes are contained in Rule 38.5.169, Statement J. The adjustment to interest expense (Adjustment No. 24) is shown on page 5. Interest is deductible for tax purposes and interest expense is calculated on the pro forma rate base using the weighted cost of debt and debt ratio from Rule 38.5.146, Statement F, page 1. The resulting interest expense deduction is an increase of $542,280 from the per books level.

The adjustments for book/tax depreciation differences and the associated deferred taxes, including differences on pro forma plant additions, are shown on page 6 as Adjustment No. 25. The calculation of book/tax depreciation and the resulting deferred taxes are shown on page 10 of Rule 38.5.169, Statement J.

Adjustment No. 26, shows current income tax expense on the pro forma adjustments to operating revenues and expenses is calculated on page 7 of Rule 38.5.169, Statement J.

The closing/filing and prior period adjustments in the current income tax accrual and in the deferred taxes are eliminated on page 8 in Adjustment No. 27. Adjusted current and deferred income taxes match those calculated for Montana and conform to past Commission practices.

Montana-Dakota recognizes plant related excess accumulated deferred income taxes on an Average Rate Assumption Method (ARAM) basis. The 2023 per books value was $300,162 and the pro forma value is $356,296 resulting in and adjustment of $56,134 found in Adjustment No. 28 as shown on page 11 of Statement J.

<u>Pro Forma Rate Base</u>

Q. How would you describe the development of the rate base?

A. The pro forma rate base is based on the average 2023 rate base and reflects known and measurable adjustments that will occur within twelve months ending December 31, 2024. The resulting rate base is stated on an average basis. The pro forma adjustments to rate base are summarized on Rule 38.5.175, page 4. Adjustment A, shown in Rule 38.5.123, Statement C, pages 2 through 4, is the known and measurable plant additions that will be in service by December 31, 2024. The increase of $19,346,247 includes additions to distribution, general and common plant and is shown on Rule 38.5.123, Statement C, pages 3 and 4. The resulting increase in average plant is $18,372,210 as summarized on page 4.

Adjustment B, shown in Rule 38.5.133, Statement D, page 2, increases the average reserve for depreciation by $7,606,740 reflecting the average per book balance and the provision for depreciation expense based on the proposed depreciation rates as applied to the existing plant and plant additions.

Q. How were the working capital items derived?

A. The working capital adjustments are summarized in Rule 38.5.141, Statement E, page 1.

Detailed information for Adjustments C through M are shown on Rule 38.5.143, Statement E, pages 1 through 11. Page 1 of Rule 38.5.143, Statement E shows materials and supplies balances restated to a thirteen month average, with actual balances through March 2024, in Adjustment C, for an increase of $56,881.

The gas in underground storage (Adjustment D) restates the balance to a thirteen month average for 2023 and is an increase of $4,415,926. The pro forma values reflect actual balances through March 2024. April through December 2024 balances reflect expected storage injection and withdrawal volumes and forecasted pricing applied to permanent storage layers the Company had in place at the end of 2023. Please see Workpaper Statement E, page 1 for more information.

Insurance expense is restated to a thirteen month average in Adjustment E with actual balances through March 2024 and balances for April through December 2024 based on the expected insurance expense. It is expected to increase $17,313.

Prepaid demand and commodity charge balances, Adjustment F, are restated to a thirteen month average, with actual balances through March 2024. April to December 2024 is based on expected projected storage activity and average pricing and results in a reduction in $78,025.

Adjustment G, H, I, J, and K reflect the unamortized loss on debt, provision for pension & benefits, provision for injuries and damages, provision for post-retirement, and unamortized redemption of preferred stock cost. These adjustments were calculated using the balance as of December 31, 2023. The annual amortization is then added to calculate a December 31, 2024 balance and the averages are based on the resulting balances, as shown on Statement E, pages 5 through 9.

The Company has consistently included pension & benefits as an asset or liability in rate base in conformance with Order 5856b in Docket No. D95.7.90

Adjustment L is the cash working capital adjustment. In the Stipulation and Agreement for Docket No. 2020.06.076, Montana-Dakota agreed that in its next rate case, it would perform a lead-lag study and utilize a cash working capital calculation. The lead-lag study is fully supported in the testimony of Mr. Michael J. Adams. The calculation of the cash working capital adjustment was performed by applying the expense lead and revenue lag days from the lead-lag study to the applicable pro forma adjustment. This resulted in an increase in the rate base of $1,149,064.

Adjustment M, shown on page 11, reflects Customer Advances for Construction which is are restated to a thirteen month average with actual balances through March 2024. April to December 2024 reflect the March 2024 balance, excluding a small non-Montana balance, and result in an increase of $162,182.

Q. Would you describe how the accumulated deferred income tax balances were developed?

A. The accumulated deferred income tax balances are summarized on page 9 of Rule 38.5.169, Statement J. The pro forma balances were derived by adding the changes to the deferred income taxes to the Pro Forma Adjusted balances and calculating the average balance.

Additionally, in Docket No. 2020.06.076, Montana-Dakota agreed that in its next case, it would provide a clear itemized breakout of its plant related Excess Accumulated Deferred Income Tax (EADIT) balances. This breakout is provided in Rule 38.5.169, Statement J, page 12.

Q. What does Rule 38.5.190, Statement O, Part A show?

A. The charts and graphs contained in Rule 38.5.190, Statement O, Part A are the pictorial exhibits that are related to the revenue requirement and required by Commission rules.

Q. Can you please explain Exhibit No.____(TRV-1)?

A. Exhibit No.____(TRV-1), which is identical to Rule 38.5.175, page 7, shows the calculation of the revenue deficiency of $9,392,775 based on the pro forma operating income and rate base and using the overall rate of return of 7.756 percent from Rule 38.5.146, Statement F, page 1.

<u>Interim Revenue Requirement</u>

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

A. Yes. As stated by Ms. Kivisto, Montana-Dakota is seeking interim rate relief in this case pursuant to the Commission's rules regarding interim rate increase requests in general rate proceedings.

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 $7,984,445 based on the pro forma cost of service.

Q. Would you please describe the variances of the interim increases from the increase requested on a final basis?

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 determined in Docket No. D2017.9.79.
- The revenue associated with the Tax Tracking Adjustment was excluded as well as Montana Property Tax.
- The depreciation rates were modified to reflect the currently approved deprecation rates from Docket No. 2020.06.076;
- Regulatory Commission Expense was adjusted to exclude the costs associated with this case.

Gas Cost Tracking Adjustment Procedure

Q. Are you proposing any changes to Rate 88 – Gas Cost Tracking Adjustment Procedure?

A. Yes, Montana-Dakota is proposing to incorporate changes in the Rate 88 - Gas Cost Tracking Adjustment Procedure tariff. The Company proposed to remove Subsection 3e and f in the Rate 88 tariff which requires the inclusion of the total Montana-Dakota sales by month and jurisdiction with annual totals. Montana-Dakota proposes that, due to the voluminous nature of the information (filing made on September 8, 2023, in Docket No. 2023.09.084 was 153 pages), the requirement should be eliminated. The Company proposes to provide this information upon request.

Exhibit No. ____(TRV-3) is the proposed Rate 88 tariff, also included in Appendix B.

Q. **Does this complete your direct testimony?**

A. Yes, it does.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ *Tara R. Vesey*

Tara R. Vesey
Manager of Regulatory Affairs

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

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$83,071,563	**$9,392,775**		$92,464,338
Transportation	1,515,228			1,515,228
Other	830,836			830,836
Total Revenues	$85,417,627	$9,392,775		$94,810,402
Operating Expenses				
Operation and Maintenance				
Cost of Gas	$49,978,363			$49,978,363
Other O&M	18,101,321			18,101,321
Total O&M	68,079,684			68,079,684
Depreciation	7,546,206			7,546,206
Taxes Other Than Income	7,816,396	$40,389	2/	7,856,785
Current Income Taxes	1,040,464	2,462,719	2/	3,503,183
Deferred Income Taxes	(1,719,415)			(1,719,415)
Total Expenses	$82,763,335	$2,503,108		$85,266,443
Operating Income	$2,654,292	$6,889,667		$9,543,959
Rate Base	$123,052,591			$123,052,591
Rate of Return	**2.157%**			**7.756%**

1/ See Rule 38.5.175, pages 5 and 6.
2/ Reflects taxes at 26.3325% after deducting Consumer Counsel tax of 0.06% and PSC tax of .37%.

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

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$76,955,782	**$7,984,445**		$84,940,227
Transportation	1,235,206			1,235,206
Other	824,312			824,312
Total Revenues	$79,015,300	$7,984,445		$86,999,745
Operating Expenses				
Operation and Maintenance				
Cost of Gas	$49,978,363			$49,978,363
Other O&M	17,239,714			17,239,714
Total O&M	67,218,077			67,218,077
Depreciation	8,337,183			8,337,183
Taxes Other Than Income	937,500	$34,333	2/	971,833
Current Income Taxes	1,112,023	2,093,465	2/	3,205,488
Deferred Income Taxes	(1,669,261)			(1,669,261)
Total Expenses	$75,935,522	$2,127,798		$78,063,320
Operating Income	$3,079,778	$5,856,647		$8,936,425
Rate Base	$126,685,922			$126,685,922
Rate of Return	**2.431%**			**7.054%**

1/ See Rule 38.5.175, pages 5 and 6.
2/ Reflects taxes at 26.3325% after deducting Consumer Counsel tax of 0.06% and PSC tax of .37%.

Exhibit No.____(TRV-3)

d. A list of FERC proceedings in which Montana-Dakota has participated with a brief description of the purpose of each and position taken by Montana-Dakota;

e. If Montana-Dakota has executed a new direct purchase contract since the last October 1 Gas Cost Tracking Adjustment, a description of what efforts, if any, were undertaken to ensure that the contract had pricing provisions which assured a firm supply of gas at a competitive price over the full term of the contract;

f. A description of what efforts, if any, Montana-Dakota has undertaken since the last October 1 Gas Cost Tracking Adjustment to utilize spot gas.

4. Gas Cost Tracking Adjustment:

a. The monthly Gas Cost Tracking Adjustment shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent Gas Cost Tracking Adjustment. 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. Any extraordinary costs, such as penalty charges and take-or-pay charges, shall be clearly identified as such and separately described in a supporting exhibit.

b. The Gas Cost Tracking Adjustment 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 gas cost tracking adjustment will be in effect and annual dk requirements.

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 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 dk's sold in each state, regardless of the actual points of delivery of such gas.

(5) All costs related to specific gas transportation services 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 Gas Cost Tracking Adjustment 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.

5. **Unreflected Gas Cost Adjustment:**
All sales rate schedules shall be subject to an Unreflected Gas Cost Adjustment to be effective on October 1 of each year. The Unreflected Gas Cost Adjustment per dk sold shall reflect amortization of the applicable balance in the Unreflected 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.

6. **Unreflected Purchased Gas Cost Account:**
   a. Items to be included in the Unreflected Purchased Gas Cost Account, as calculated in accordance with Subsection 6(b) are:

      (1) Charges for gas supply which Montana-Dakota is unable to reflect in a Gas Cost Tracking Adjustment by reason of the twenty-five (25) cent minimum limitation set forth in Subsection 2(b).

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

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

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

   b. The amount to be included in the Unreflected Purchased Gas Cost Account in order to reflect the items specified in Subsections 6(a)(1), (2), and (3) shall be calculated as follows:

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

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

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

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

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

c. Reduction of Amounts in the Unreflected Purchased Gas Cost Account:

(1) The amounts in the Unreflected Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective unreflected gas cost adjustment included in rates for that month (as calculated in Section 5) by the dk's sold during that month

under each rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. Time and Manner of Filing:

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

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

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2024.05.061

Direct Testimony
of
Ronald J. Amen

July 15, 2024

TABLE OF CONTENTS

I. <u>INTRODUCTION AND SUMMARY</u>

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

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.

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 27 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 **Appendix 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 proposed class revenue apportionment and 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 L, Statement M, Statement O, Part B, and the following exhibits:

- Exhibit No.____(RJA-1), Proposed Revenue Allocation
- Exhibit No.____(RJA-2), Revenues at Current and Proposed Rates, and
- Exhibit No.____(RJA-3), Residential and Firm General Service 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.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (a historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. 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.

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 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. Are cost of service studies an application of economic theory to cost allocation?

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. Rather, it is 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. The logic for this concept is that if customers' prices exceed incremental cost, those customers contribute 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 stand-alone because the customer would not be willing to participate in the service offering if prices exceed stand-alone costs.

Stand-alone costs are 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 stand-alone costs for some customers, prices must nevertheless be set below the stand-alone costs, 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 Small Firm General, Small Interruptible and Large Interruptible customers. The costs related to these facilities from the following plant accounts were directly assigned to the Small Firm General, Small Interruptible and Large Interruptible customer classes.

- Account 375 – Structures and Improvements. Direct assignment to Small Interruptible (Rate 71), and Large Interruptible (Rate 82).
- Account 379 – Measuring & Regulating Equipment - City Gate. Direct assignment to Small Interruptible (Rate 71), and Large Interruptible (Rate 82).
- Account 383 – Service Regulators. Direct assignment to Small and Large Firm General (Rate 70), Small Interruptible (Rate 71), and Small Interruptible (Rate 81).
- Account 385 – Industrial Measuring & Regulating Station Equipment. Direct assignment to Small Interruptible and Large Interruptible (Rates 81 and 82).

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. In order to establish the cost responsibility of each customer class, the COSS consists of a three-step analysis process: (1) cost functionalization, (2) cost classification, and (3) cost allocation. The first step, cost 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 related expenses), distribution and general. The general function includes costs that cannot be directly assigned to the primary operating functions of production, storage, transmission, and distribution. These costs are functionalized in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"). 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 legislative and regulatory policies and evidentiary 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 Montana 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, distribution-only and multi pressure-based system.

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 five customer classes: Residential Service (Tariff Schedule 60); Small Firm General Service (Tariff Schedule 70, 72 and 74); Large Firm General Service (Tariff Schedule 70, 72 and 74); Small Interruptible Service (Tariff Schedules 71 and 81); and Large Interruptible Service (Tariff Schedules 82 and 85).

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 35% of its investment in distribution mains as customer related and 65% 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, which is the method relied upon in the Company's cost study, 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.

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 employed provided poor statistical properties that yielded results that were unsatisfactory. Therefore, the Company relied upon the minimum system study for determining the customer component of distribution mains.

The most commonly installed, minimum-sized distribution mains analysis focused on 2-inch plastic pipe. Out of the approximately 8.7 million total feet of distribution mains installed in Montana-Dakota's Montana service territory, 5.1 million feet were less than or equal to 2-inch plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic, with over 1.2 million feet installed over the past ten years; approximately 76 percent of all mains installations. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 35.4%.

Q. Do the results of the minimum system method described above therefore support the 35% classification of distribution mains as customer related, used by the Company?

A. Yes. Applying the average unit cost of $11.43 per foot (in 2024$) for a 2-inch plastic distribution main to the Company's total footage of distribution mains, adjusted for the load carrying capacity of a pipeline of this size and material type, results in an investment amount equivalent to approximately 35% of the total investment in distribution mains.

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.

Q. Why is Montana-Dakota's design day demand an appropriate method of allocating demand related investment in distribution mains?

A. Use of a utility's design day demand is a superior method for purposes of deriving demand allocation factors for a number of reasons. These reasons include:

(1) A utility's gas system is designed, and consequently costs are incurred, to meet design day demand. In contrast, costs are not incurred on the basis of an average of peak demands.

(2) Design day demand is more consistent with the level of change in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time.

(3) Design day demand provides more stable cost allocation results over time.

Q. Please explain why Montana-Dakota's design day demand best reflects the factors that actually cause costs to be incurred.

A. Montana-Dakota must consistently rely upon design day demand in the design of its own transmission and distribution facilities required to serve its firm service customers. More importantly, design day demand directly measures the gas demand requirements of the utility's firm service customers which create the need for Montana-Dakota to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. In my opinion, there is no better way to capture the true cost causative factors of Montana-Dakota's operations than to utilize its design peak day requirements within its cost of service studies.

Q. Please explain why use of design day demand provides more stable cost allocation results over time.

A. By definition, a utility's design day peak is as stable a determinant of planned capacity utilization as you can derive. If it were not a stable demand determinant, the design of a utility's gas system and supply portfolio would tend to vary and make the installation of facilities and acquisition of supply resources and capacity a much more difficult task. Therefore, use of design day demands provides a more stable basis than any of the other demand allocation factors available based on either actual peak day demand or the averaging of multiple peak days.

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 balance of the costs in Account 383 (House Regulators) that were not directly assigned were based on the weighted customers at distribution which is a meter weighted allocation. The classification and allocation of the balance of the costs in Account 385 (Industrial M&R Equipment) that were not directly assigned were based on the design peak day excluding the Residential and Small Firm General classes. The costs in Accounts Nos. 374 (Land & Right of Way), 375 (Structures and Improvements), and 378 & 379 (Measurement & Regulator Station Equipment – General & City Gate) were classified and allocated based on the distribution mains allocator. The costs in Account 387 (Other Distribution Equipment) were classified and allocated based on the sum of the allocation of Distribution Plant Account Nos. 375-385.

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 & PragmaCAD (CC&B & PCAD) 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 customers allocator from the meter study.

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 L.

A. Statement L-1, pages 1 – 3, 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 7.756 percent were to be earned for the demand, energy, and customer cost components of each rate schedule. A summary of the results by the major rate classifications, Residential, Small Firm General, Large Firm General, Small Interruptible Sales and Transportation, and Large Interruptible Sales and Transportation is provided in Statement L, Schedule L-1, pages 4 – 5.

Statement L, Schedule L-2, pages 1 – 30, is a report of the rate base, income statement and pro forma adjustments 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 L, Schedule L-3.

The COSS is based on the Montana natural gas operations results for the 12 months ended December 31, 2023 as adjusted to reflect the pro forma adjustments sponsored by Company witness Ms. Vesey.

Q. Has the Company filed a Marginal Cost Study?

A. No. On May 24, 2024, the Company filed a request for waiver of the Commission's Minimum Rate Case Filing Standards that require the preparation and filing of a marginal cost study as part of an application a general increase. On June 25, 2024, the Commission granted the requested waiver of this filing requirement for this rate case.[1]

Q. Please summarize the results of the COSS.

A. As shown in Schedule L-1, the overall rate of return for Montana natural gas service is 2.157%, based on the actual results of operations for the twelve months ended December 31, 2023, adjusted for known and measurable changes, and excluding Montana taxes recovered through Rate 87. The returns by customer class are shown below:

- Residential Service -2.097%
- Small Firm General Service 7.862%
- Large Firm General Service 16.706%
- Small Interruptible Sales & Transportation 21.523%
- Large Interruptible Sales & Transportation 13.639%

[1] See Notice of Commission Action, 2024.05.061, Service Date June 25, 2024.

Q. Please describe the information provided in Statement O, Part B.

A. Statement O, Part B, consists of twelve pages of illustrative charts and graphs depicting various aspects of the COSS results and proposed revenue allocation by customer class, as required by Rule 38.5.190.

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 stand-alone costs, 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 an 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 $8.9 million to its customer classes, excluding the change in revenues due to changes in the Company's gas tax tracking adjustment.

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.

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 ratios for the larger non-residential classes: Large Firm General, Small Interruptible Sales & Transportation and Large Interruptible Sales & Transportation (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 (Tariff Schedules 60), Small Firm General Service (Tariff Service 70, 72 and 74), Large Firm General Service (Tariff Service 70, 72 and 74), Small Interruptible Sales & Transportation Service class (Tariff Schedules 71 and 81) and Large Interruptible Sales & Transportation Service (Tariff 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. Not only was the Residential Service class below unity (< 1.00 revenue-to-cost ratio) in the COSS results, but the class revenues also produced a negative rate of return ("ROR") at -2.097% (Statement L, Schedule L-1, page 5 of 5). The proposed revenue increase to the residential class will improve the class' revenue to cost ratio from 0.61 to 0.88. While the Small Firm General Service class' rate of return at current rates was 7.862% (Statement L, Schedule L-1, page 5 of 5), its revenue-to-cost ratio was just below unity (0.97) at the Company's proposed ROR of 7.76% (Statement M, page 2 of 10). The proposed revenue increase to this class will result in a revenue-to-cost ratio above parity at 1.28.

The COSS results for the three 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 will mean these three classes parity ratio levels will converge from current levels relative to unity.

The resulting allocation of the total revenue increase of $8.9 million, excluding the property tax tracker, to the respective rate classes is presented in

Statement M, page 2 of 10. The target revenue increase percentages range from 16.31% to Residential, 12.51% to Small Firm General, 1.07% to Large Firm General, 2.15% to Small Interruptible, and 4.54% to Large Interruptible (excluding tax tracker).

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.

Exhibit No.___ (RJA-2), Revenues at Current and Proposed Rates, presents summaries by customer class of the proposed revenue increase. This exhibit displays the revenues calculated under the present and proposed rates for each customer class / tariff rate schedule. The proposed revenue increase by class and corresponding percentage is also shown.

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 the following rate design changes to its current tariff schedules. For customers served under Residential Service (Tariff Schedule 60), Small Firm General Service (Tariff Schedule 70, 72 and 74); Large General Service (Tariff Schedule 70, 72 and 74) , Small Interruptible Sales & Transportation Service (Tariff Schedules 71 and 81); and Larg Interruptible Sales and Transportation Service (Tariff Schedules 82 and

85), Montana-Dakota proposes to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service, as shown on Statement L . Following the revenue increases recovered through the Basic Service Charges, the remaining allocated revenue increases for these customer classes will be recovered in their respective volumetric Distribution Delivery Charge components.

Q. Please describe the proposed changes to the Basic Service Charges for the respective tariff schedules.

A. As seen on page 3 of Statement M the Basic Service Charge under Residential Rate 60 is proposed at $0.55 per day which reflects an average monthly charge of $16.72, an increase of approximately $7.60 per month from the currently effective charge. The proposed charge is only 58% of the customer cost component identified as $28.78 per month as shown on Statement L, Schedule L-1, page 1, and is only 56% of the total fixed costs assigned to the Residential class of $29.71 per month, which reflects both the customer and demand components of the class's allocated cost of service.

The Basic Service Charge applicable to Firm General Service customers with meters rated less than 500 cubic feet per hour is proposed at $1.05 per day, and $2.30 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 $31.92 and $69.92 respectively representing an increase of $13.68 per month in the Basic Service Charge applicable to customers using meters rated less than 500 cubic feet per hour and an increase of $16.72 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 4 and 5 of statement M.

The proposed Basic Service Charge applicable to Small Interruptible Sales Transportation Service customers is $360.00 per month, which represents an increase of $48.00 per month and brings the charge up to the total allocated customer related costs for the class. The rate calculations for the Small Interruptible Service class are included on page 6 of Statement M.

Page 7 of Statement M details the proposed Basic Service Charge applicable to Large Interruptible Sales Transportation Service Customers of $750.00 per month, which represents an increase of $182.75 per month and brings the charge up to the total allocated customer related costs for the class.

These increases to the Basic Service Charges will provide significant improvement in the recovery of the fixed customer-related 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. 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 small relative to the combined total bill, including the gas commodity charge incurred by the customer. As depicted in the accompanying Exhibit No.___(RJA-3), the portion of the typical residential customer's annual bill represented by the average Basic Service Charge increase of $7.60 per month is approximately 12% of the total bill. The effect of raising the proposed Basic Service Charge by $.25 per day, the equivalent of

$7.75 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[2] is 60% 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 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 more of its fixed customer-related costs in the 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

[2] Montana-Dakota's proforma cost of gas in the COSS is $4.762 per Dk.

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 moderately higher 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 as further discussed in Section VII.

VII. 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 78 dekatherms (Dk) per year is shown on page 1 of Exhibit No.___(RJA-3), Residential and Firm General Service Bill Comparisons. The average monthly increase for this residential customer under the Company's proposed rate design is $8.68 or 16.40%.

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 143 Dk per year is shown on page 2 of Exhibit No.___(RJA-3). The average monthly increase for this customer under the Company's proposed rate design is $12.34 or 12.07%. The monthly and annual bill impacts for a typical Large Firm General customer using 1,084 Dk per year is shown on page 3 of the exhibit. The average monthly increase for this residential customer under the Company's proposed rate design is $0.32 or 0.05%.

A presentation of the annual billing impacts for the Residential and Firm General Service classes is provided in Pages 8-10 of Statement M.

Q. Does this conclude your direct testimony?

A. Yes.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ *Ronald J. Amen*

Ronald J. Amen
Managing Partner
Atrium Economics, LLC

ATRIUM ECONOMICS
CENTERED ON ENERGY

Ronald J. Amen

Managing Partner

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

University of Nebraska,
Bachelor of Science with Distinction, Business Administration, Finance and Economics

YEARS EXPERIENCE

44

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 Canada Energy Regulator (CER), 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. The case resulted in a settlement with all parties.

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, 2021)
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. Retained in 2021 to update quantitative analysis of the operation of the transportation balancing rules for reporting requirements of the BCUC in 2022.

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

Confidential Multi-Jurisdiction Gas Utility (2021-2022)

Retained by the multi-jurisdiction interstate transmission pipeline and local distribution utility ("client") to assist it in identifying and supporting a natural gas supply solution to satisfy additional deliverability requirements with the goals of minimizing costs, enhancing system resiliency, and introducing renewable fuels into its system. Reviewed the process and analyses that had been conducted to-date (including all underlying assumptions) and provided insight on the best path forward. The goal of the effort was to help prepare client for internal approval of the process and recommended path forward, and ultimately the development and approval of the necessary regulatory filings at the federal, state, and local levels. Atrium evaluated a broad spectrum of regulatory, economic, market-related, and logistical considerations in order to advise the client on the best path forward in utilizing LNG to meet its future deliverability requirements. Specific components of Atrium's analysis included regulatory approvability, rate design and cost recovery risk, site location (including siting LNG in multiple locations in multiple states), ownership structure, and ability to incorporate RNG and hydrogen into Utility's system to decarbonize the pipeline system.

Great Plains Natural Gas (2021-2022)

Retained to review the gas supply procurement practices and objectives of Great Plains, the interstate pipeline, storage and supply contracts, and other information available to Great Plains leading up to and throughout the severe weather event that occurred from February 13-17, 2021, and the actions by Great Plains personnel in response to the weather event, as part of a state-wide investigation by the Minnesota Public Utilities Commission. Expert testimony filed on behalf of Great Plains.

Fortis BC Energy, Inc. (2011, 2021)

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. In 2021, retained to refresh all quantitative analysis of the operation of the GSMIP for reporting requirements of the BCUC in 2022.

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 – 2003)
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

Philadelphia Gas Works PGW (2023)
Mr. Amen led an Atrium team engaged by PGW to review the mechanics, input data, billing controls, and weather trends surrounding PGW's Weather Normalization Adjustment ("WNA") formula to understand the factors that contributed to the abnormally high WNA charges in June 2022. Atrium's review identified structural factors inherent in PGW's WNA mechanism that may have contributed to the anomalous WNA amounts billed to customers in June 2022. Mr. Amen filed testimony with Atrium's findings and recommendation in the pending general rate case before the Pennsylvania Public Utility Commission.

Potomac Electric Power Company (PEPCO) (2022-2023)
Mr. Amen led an Atrium team engaged by PEPCO on behalf of services requested by the Public Service Commission of the District of Columbia ("DC Commission"), for comprehensive evaluation of the processes, procedures, mechanics, and internal controls surrounding PEPCO's Bill Stabilization Adjustment ("BSA"). Atrium provided independent audit services sought by the DC Commission, including a) independently evaluate the timing, impact and magnitude of the billing determinant error that was identified during Formal Case No. 1156; b) independently confirm that current BSA processes and procedures are properly and timely executed as designed; c) independently confirm that current Pepco BSA internal controls are properly and timely executed; d) independently identify any recommended process and procedural improvements, as well as any recommended changes in existing internal controls or new internal controls; and e) independently conduct a comprehensive review of Pepco's BSA deferral balances by customer class, with an overall determination of the breakdown of BSA deferral balances by key drivers for each customer class. Our audit report and recommendations were filed with the DC Commission in July 2023.

Summit Natural Gas of Maine, Inc. (2022 - 2023)
Mr. Amen provided revenue requirement, allocated cost of service, class revenue apportionment, rate design, and expert witness testimony support for the utility's gas general rate case and multi-year rate plan before the Maine Public Utilities Commission. Responsibilities included determination of an optimal normal weather period for purposes of normalizing test year billing determinants, followed by the weather normalization process of determining a representative level of gas throughput for the Company's test year. The case resulted in an all-party settlement before the Maine PUC.

Black Hills Energy Arkansas (2021-2022)

Mr. Amen provided allocated cost of service, class revenue apportionment, rate design for natural gas infrastructure mechanisms, and expert witness support for the utility's gas general rate case before the Arkansas Public Service Commission. The case resulted in a settlement before the Arkansas PSC.

Until Electric System and Northern Utilities, Inc. (2021 - 2022)

Mr. Amen provided allocated cost of service, marginal cost of service, class revenue apportionment, rate design, and expert witness support for the utility's separate electric and gas general rate cases before the New Hampshire Public Utilities Commission, including expert witness testimony. The cases resulted in settlements before the NHPUC.

Manitoba Hydro – Centra Gas Manitoba (2021-2022)

Retained to provide an independent review of the cost of service methodologies employed for Centra Gas Manitoba Inc.'s natural gas operations. Atrium prepared a report filed with the Manitoba Public Utility Board documenting and supporting our assessment of Centra's existing COSS methods in conformance with the regulatory requirements of the MPUB. Focusing on the trends of Canadian gas distribution utilities, the COSS method utilized in the current COSS was reviewed against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market. Centra's 2022 rate application based on the recommendations in our report was approved by the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021, 2022 - 2023)

Mr. Amen provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utilities' general rate cases before the Montana Public Service Commission (MPSC) and North Dakota Public Service Commission (NDPSC). 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. Supported the Straight Fixed-Variable Rate Design (SFV) in North Dakota with analysis showing low-income residential customers would experience lower annual bills under the SFV rate design than a volumetric weighted rate design. Provided a presentation at a public input hearing and oral testimony at Commission hearings in both jurisdictions. SFV rate design was approved by the North Dakota PSC. The cases resulted in settlements approved by the respective Commissions.

Mr. Amen also represented the client's interests (as well as those of neighboring utility clients NW Natural and Puget Sound Energy) in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Mr. Amen supported electric general rate case filings in Montana and North Dakota, including a marginal cost study in Montana, and allocated cost studies, revenue apportionment and rate design in both jurisdictions.

Mr. Amen recently supported a gas general rate case filing in MDU's Idaho affiliate, Intermountain Gas. Support included a class level, design day load study across the utility's seven temperature zones, using a combination of AMI (60% penetration) and monthly billing data, class allocated cost of service study, class revenue apportionment, and rate design.

Mr. Amen is currently supporting gas and electric general rate case filings in MDU's South Dakota service territory, including gas and electric allocated cost studies, revenue apportionment and rate design (filed August 2023).

Chesapeake Utilities Corporation (2020 – 2021)
Reviewed and evaluated Chesapeake's Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Kansas City, KS Board of Public Utilities (2019 – 2020)
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, 2023)

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 incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently providing cost of service and rate design for the 2023 – 2024 rate filing. Future project work involves 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 discussed 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, 2021)
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 five general rate cases before the Indiana Utility Regulatory Commission. The 2021 rate case is currently pending before the IURC.

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 the latest general rate case, Mr. Amen sponsored expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement in the 2020 general rate case.

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
- Kentucky Public Service Commission
- Maine Public Utilities Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- South Dakota Public Utilities 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.
PROPOSED REVENUE ALLOCATION
GAS UTILITY - MONTANA

	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Revenue to Cost Ratio Under Current Rates	0.76	0.61	0.97	1.34	1.39	1.21
Parity Ratio at Current Rates	1.00	0.80	1.28	1.76	1.83	1.59
Revenues at Equalized Rates of Return						
Revenue Increase excluding tax tracker	8,938,379	10,748,048	113,219	(1,567,344)	(226,050)	(129,495)
Total revenue at equalized rates of return (ex. tax tracker)	37,151,004	27,604,803	3,703,413	4,641,912	580,647	620,228
Parity Ratio	1.00	1.00	1.00	1.00	1.00	1.00
Secnario A: Equal Percentage Increase						
System average increase	0.00%	31.68%	31.68%	31.68%	31.68%	31.68%
Revenue Increase excluding tax tracker	8,938,379	5,340,590	1,137,452	1,967,229	255,579	237,529
Total revenue at equalized rates of return (ex. tax tracker)	37,151,004	22,197,345	4,727,646	8,176,485	1,062,276	987,252
Percent Increase	31.68%	31.68%	31.68%	31.68%	31.68%	31.68%
Parity Ratio	1.00	0.80	1.28	1.76	1.83	1.59
Secnario B: No Class Increase Above Parity						
Revenue Increase excluding tax tracker	8,938,379	8,825,160	113,219	0	0	0
Total revenue at equalized rates of return (ex. tax tracker)	37,151,004	25,681,915	3,703,413	6,209,256	806,697	749,723
Percent Increase	31.68%	52.35%	3.15%	0.00%	0.00%	0.00%
Parity Ratio	1.00	0.93	1.00	1.34	1.39	1.21
Proposed Class Revenues						
% Increase by Rate Class			31.68%	3.55%	4.09%	23.76%
Revenue Increase excluding tax tracker	8,938,379	7,498,702	1,137,452	220,330	32,970	48,925
Total revenue at equalized rates of return (ex. tax tracker)	37,151,004	24,355,457	4,727,646	6,429,586	839,667	798,648
Percent Increase	31.68%	44.48%	31.68%	3.55%	4.09%	6.53%
Parity Ratio	1.00	0.88	1.28	1.39	1.45	1.29

Source: Statement L

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - MONTANA
Pro Forma 2024

	Pro Forma					**Proposed Total Revenues**		
Customer Class/Rate	Customers 1/	Dk 1/	Revenue 1/	Property Tax Increase	Distribution Increase	Total Revenue	$ Increase	% Increase
Residential - Rate 60	78,431	6,115,799	$49,801,616	$669,541	$7,499,313	$57,970,470	$8,168,854	16.40%
Firm General Service - Rates 70 & 72	10,785	4,156,306	31,822,954	(164,028)	1,359,129	33,018,055	1,195,101	3.76%
Small Interruptible								
Sales - Rate 71	19	230,122	1,036,515					
Transport - Rates 81	27	568,962	678,174					
Total Small Interruptible	46	799,084	1,714,689	(28,068)	32,889	1,719,510	4,821	0.28%
Large Interruptible								
Sales - Rate 85	1	104,045	410,478					
Transport - Rate 82	3	2,897,218	837,054					
Total Large Interruptible	4	3,001,263	1,247,532	(21,882)	53,374	1,279,024	31,492	2.52%
Total Montana	89,266	14,072,452	$84,586,791	$455,563	$8,944,705	$93,987,059	$9,400,268	11.11%

1/ Rule 38.5.164, Statement H, Pages 12-13.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE
Pro Forma 2024

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	14	$101.30	$110.20	$8.90	8.79%
February	12	87.35	95.40	8.05	9.22%
March	12	88.46	97.35	8.89	10.05%
April	8	62.40	70.98	8.58	13.75%
May	5	43.51	52.34	8.83	20.29%
June	2	23.88	32.40	8.52	35.68%
July	1	17.83	26.62	8.79	49.30%
August	1	17.83	26.62	8.79	49.30%
September	2	23.88	32.40	8.52	35.68%
October	3	30.67	39.48	8.81	28.73%
November	7	55.99	64.55	8.56	15.29%
December	11	82.03	90.92	8.89	10.84%
Total	78	$635.13	$739.26	$104.13	16.40%
Average Increase per Month				$8.68	

RATE 60	Current	Proposed
Basic Delivery Charge	$0.30	$0.55
Distribution Delivery	$1.352	$1.408
Tax Tracker Adjustment 1/	22.6700%	18.4388%
Cost of Gas	$4.762	$4.762

1/ Docket No. 2023.10.089, effective January 1, 2024.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE (< 500 Cubic Feet Per Hour Meters)
Pro Forma 2024

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	28	$210.32	$218.78	$8.46	4.02%
February	25	188.03	195.74	7.71	4.10%
March	23	176.84	186.60	9.76	5.52%
April	14	115.84	127.42	11.58	10.00%
May	8	76.39	90.05	13.66	17.88%
June	2	35.48	50.18	14.70	41.43%
July	0	22.82	38.55	15.73	68.93%
August	1	29.52	44.99	15.47	52.41%
September	1	28.78	43.75	14.97	52.02%
October	5	56.31	70.73	14.42	25.61%
November	14	115.84	127.42	11.58	10.00%
December	22	170.15	180.16	10.01	5.88%
Total	143	$1,226.32	$1,374.37	$148.05	12.07%

Average Increase per Month $12.34

RATE 70	Current	Proposed
Basic Delivery Charge	$0.60	$1.05
Distribution Delivery	$1.577	$1.414
Tax Tracker Adjustment 1/	22.6700%	18.4388%
Cost of Gas	$4.762	$4.762

1/ Docket No. 2023.10.089, effective January 1, 2024.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE (> 500 Cubic Feet Per Hour Meters)
Pro Forma 2024

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	189	$1,312.25	$1,294.06	($18.19)	-1.39%
February	164	1,141.03	1,125.87	(15.16)	-1.33%
March	160	1,121.11	1,108.45	(12.66)	-1.13%
April	101	730.09	728.13	(1.96)	-0.27%
May	70	527.92	532.45	4.53	0.86%
June	31	268.72	280.13	11.41	4.25%
July	23	218.14	231.66	13.52	6.20%
August	23	218.14	231.66	13.52	6.20%
September	23	215.99	228.93	12.94	5.99%
October	49	389.51	398.06	8.55	2.20%
November	100	723.50	721.72	(1.78)	-0.25%
December	151	1,061.79	1,050.86	(10.93)	-1.03%
Total	1,084	$7,928.19	$7,931.98	$3.79	0.05%
Average Increase per Month				$0.32	

RATE 70	Current	Proposed
Basic Delivery Charge	$1.75	$2.30
Distribution Delivery	$1.491	$1.383
Tax Tracker Adjustment 1/	22.6700%	18.4388%
Cost of Gas	$4.762	$4.762

1/ Docket No. 2023.10.089, effective January 1, 2024.

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2024.05.061

Direct Testimony
of
Stephanie Bosch

Q. Please state your name and business address.

A. 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. 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 filings.

Q. 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 pro forma gas revenues, as included in Statement H, pages 6 through 23, of this Application, the proposed rate schedules provided in Appendix B to the Application, and other proposed changes in the Company's Montana gas tariff.

Additionally, I present the apportionment of the interim increase to the various rate classes and the proposed interim rate schedules provided in Appendix A to the Application for Interim Increase in 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 North Dakota and Wyoming and the Public Utilities Commissions of Minnesota and South Dakota.

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

A. I am sponsoring Statement H, pages 6 through 23 and the proposed rate schedules provided in Appendix B to the Application, with the exception of the proposed changes to Gas Cost Tracking Adjustment Procedure Rate 88, which is sponsored by Ms. Tara Vesey and Exhibit No. ___(SB-1) proposed new rate schedule Summary Billing Rate 115, Exhibit No. ___(SB-2) calculation of proposed demand charge under Firm

General Contracted Demand Service Rate 74, and Exhibit No. ___(SB-3) revenue under current and proposed interim rates, excluding Gas Tax Tracking Adjustment Rate 87 revenue.

I am also sponsoring the proposed interim rate schedules provided in Appendix A to the Interim Application.

Gas Revenues at Current Rates

Q. Please explain the calculation of revenue at current rates included in Statement H, pages 6 through 23.

A. The Company applied the Basic Service Charges and Distribution Delivery or Demand Charges applicable under each rate schedule, and as authorized in Docket No. 2020.06.076 effective April 1, 2021 to the pro forma customers and volumes, identified by Mr. Nathan Bensen, to derive the revenues shown on Statement H, pages 6 through 23. Interruptible sales and transportation customers were priced at the applicable rate schedule's maximum rate, unless service is provided under a contract rate. The current tax tracking adjustment rate of 22.6700% was then applied to the revenue as shown on Statement H pages 6 through 23. The Cost of Gas rates are reflective of the pro forma 2024 commodity gas rate and demand costs as of March 1, 2024, excluding the surcharge.

Proposed Tariff Changes

Q. The Company is proposing a new rate schedule in this case. Please explain this new rate schedule which is provided herein as Exhibit No. ___(SB-1).

A. Summary Billing Plan Rate 115 (Rate 115) is an optional billing arrangement where qualifying customers that have multiple premises in Montana can choose to consolidate the billing of those premises under one account. The new rate schedule outlines the general availability of this new billing arrangement as well as the terms and conditions for enrolling in and maintaining eligibility under the plan.

The proposed rate schedule is in response to customers requesting the ability to consolidate multiple monthly Montana-Dakota bills into one account which in turn equates to one monthly bill and one payment. The Company recognizes the value of a bill consolidation program for participating customers; however, believes such an optional billing arrangement is best managed through a defined program that helps inform interested and participating customers of their responsibilities as well as the Company's parameters for continued participation in the plan.

Q. Briefly describe any other changes the Company is proposing to its Montana gas tariff.

A. The Company is proposing the following changes to its gas tariff as clearly identified in the legislative copy of the tariffs provided in Appendix B of the Application:

- The rates described by Mr. Amen have been incorporated into the proposed tariffs.

- Update the Distribution Demand Charge under Rate 74 to reflect the distribution demand-related results of the Company's class cost of service study, shown in Statement L, Schedule L-1, as shown on Exhibit No. ___(SB-2).
- Introduce new or update existing provisions within the Company's Conditions of Service Rate 100:
    - Allows the Company to turn a customer's gas meter on and, if no gas use is detected at that time, leave the gas meter on and permit the customer to relight any pilot lights on their equipment at the customer's earliest convenience. This will eliminate the required presence of the customer at the time of a gas meter turn on, if the requesting customer consents to, and accepts responsibility for, their pilot relight(s). (Rate 100, Section IV.2 Liability/Customer's Equipment)
    - Updates the annual authorized usage by rate used in the determination of the Non-Residential Reconnection Fee for Seasonal or Temporary Customers, under Conditions of Service Rate 100, to reflect each respective rate class's average annual use from this case. (Rate 100, Section V.21

General Terms and Conditions/Reconnection Fee for Seasonal or Temporary Customers)

- 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. How was the proposed interim revenue requirement apportioned among the customer classes?

A. The interim revenue increase of $7,984,445, identified by Ms. Vesey, is proposed to be billed as a separate line item on customers' bills based on 28.857 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 contract rate customers.

The calculations supporting the application of the interim increase to each rate class are provided in Statement M attached to the Application for Interim Increase in Natural Gas Rates. The proposed tariff sheets reflect the proposed interim rate of 28.857 percent applicable to the amounts billed under the Basic Service Charge and the Distribution Delivery or Demand Charges. The interim rate will not be applicable to the amounts billed under the Cost of Gas, Gas Tax Tracking Adjustment and Conservation Tracking Adjustment. The interim increase represents an overall increase of 10.21 percent over the Company's pro forma revenues, excluding the Gas Tax Tracking Adjustment. Exhibit No. ___(SB-3) page 2 shows a typical residential bill for a Montana-Dakota customer reflecting the proposed interim increase, indicating an average monthly increase of $5.17 from current rates.

Q. Does this conclude your testimony?

A. Yes.

Verification

The prepared testimony is true and accurate to the best of my knowledge, information, and belief.

/s/ *Stephanie Bosch*

Stephanie Bosch
Regulatory Affairs Manager

Public Service Commission of Montana

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

Natural Gas Service

Volume No. 7
Original Sheet No. 64

SUMMARY BILLING PLAN Rate 115

Availability:

Under the Company's Summary Billing Plan, customers are provided an optional billing arrangement under which a customer's multiple premises may be consolidated into one billing statement each month. This billing arrangement is available in all communities served by the Company for customers who voluntarily agree to participate in the Summary Billing Plan and who continue to meet the availability and terms and conditions of the plan.

The Company may limit the number of premises participating in the plan and exclude services based on rate and/or customer class or credit standing with the Company. Seasonal, short-term, or temporary customers will not be allowed to enroll. Participation in other optional programs such as Balanced Billing may also limit a customer's ability to participate in this billing arrangement. This is not an all-inclusive list of exclusions and service enrollment is at the Company's sole discretion.

General Terms and Conditions:

1. A customer requesting Summary Billing must provide 45 days advanced notice of their request to enroll.

2. Customer agrees to contract for Summary Billing for a minimum of one year.

3. Each service enrolled in the Summary Billing Plan shall be billed at the otherwise applicable rate schedule.

4. The Company, at its sole discretion, will select the bill date for an enrolled customer's Summary Bill.

5. Enrolled customers need only make one payment each month covering the total amount due for all services included in the Summary Bill.

6. Payment policies remain in effect for each customer participating in the plan. Any determination of delinquencies will be based on the bill date of the Summary Bill.

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

SUMMARY BILLING PLAN Rate 115

   a. If a customer participating in the Summary Billing Plan falls into arrears, the Company, at its sole discretion, may discontinue this optional billing arrangement and revert the services into separate billing statements.

7. Either the customer or the Company may cancel a customer's Summary Billing Plan with a 45-day advanced notice of cancellation. Upon cancellation of the plan, a customer's services will revert into separate billing statements.
   a. Upon cancellation of a Summary Billing Plan, the customer may not request the establishment of a new Summary Billing Plan for at least one year after cancellation.

8. The Company will not be liable for any customer costs which may result from any refusals, delays or failures resulting from requests for, or changes to, a customer's Summary Billing Plan.

Montana-Dakota Utilities Co.
Gas Utility - Montana
Calculation of Rate 74 Distribution Demand Charge
2024 Rate Case

Rate Classes	Net Distribution Cost of Service - Demand Component 1/	Distribution Level Peak 2/	Annual Cost	Rate 74 Demand Charge
Residential	$5,690,100	76,864		
Small Firm General	1,218,678	16,386		
Large Firm General	2,937,347	34,198		
Small Interruptible	473,516	4,283		
Large Interruptible	693,321	7,938		
	$11,012,962	139,669	$78.85	$6.57

1/ Class Cost of Service Study, Cost by Component
2/ Class Cost of Service, Design Day Deliveries

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES - INTERIM
GAS UTILITY - MONTANA
PRO FORMA 2024

	Pro Forma 1/					
Customer Class/Rate	Customers	Dk	Revenue	Proposed Revenue Increase	Total Proposed Revenue	Percent Increase
Residential - Rate 60	78,431	6,115,799	$45,980,190	$4,864,354	$50,844,544	10.58%
Firm General Service - Rates 70, 72 & 74	10,785	4,156,306	29,601,418	2,827,827	32,429,245	9.55%
Small Interruptible						
Sales - Rate 71	19	230,122	978,967			
Transport - Rates 81	27	568,962	552,844			
Total Small Interruptible	46	799,084	1,531,811	232,788	1,764,599	15.20%
Large Interruptible						
Sales - Rate 85	1	104,045	395,207			
Transport - Rate 82	3	2,897,218	682,362			
Total Large Interruptible	4	3,001,263	1,077,569	59,416	1,136,985	5.51%
Total Montana	89,266	14,072,452	$78,190,988	$7,984,385	$86,175,373	10.21%

1/ Rule 38.5.177, Statement M, Page 1.

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

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	14	$94.90	$103.05	$8.15	8.59%
February	12	81.77	88.88	7.11	8.70%
March	12	82.67	90.04	7.37	8.91%
April	8	57.91	63.63	5.72	9.88%
May	5	39.87	44.50	4.63	11.61%
June	2	21.23	24.61	3.38	15.92%
July	1	15.41	18.48	3.07	19.92%
August	1	15.41	18.48	3.07	19.92%
September	2	21.23	24.61	3.38	15.92%
October	3	27.64	31.49	3.85	13.93%
November	7	51.80	57.13	5.33	10.29%
December	11	76.55	83.52	6.97	9.11%
Total	78	$586.39	$648.42	$62.03	10.58%
Average Increase per Month				$5.17	

RATE 60	Current	Proposed
Basic Delivery Charge	$0.30	$0.30
Distribution Delivery	$1.352	$1.352
Tax Tracker Adjustment 1/	0.0000%	0.0000%
Interim Rate 2/		28.857%
Cost of Gas	$4.762	$4.762

1/ Excluding Gas Tax Tracking Adjustment Rate 87.
2/ Rule 38.5.177, Statement M, page 1, Interim.