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

June 30, 2025

Secretary & Chief Counsel
Wyoming Public Service Commission
Hansen Building, Suite 300
2515 Warren Avenue
Cheyenne, WY 82002

RE: General Rate Increase in Retail Electric Service Utility Rates
Docket No. 20004-___-ER-25

Montana-Dakota Utilities Co. (Montana-Dakota or Company) herewith submits its application to increase its electric service utility rates. Montana-Dakota is also requesting approval of changes to its tariffs. This filing is made in accordance with Section 37-3-106 of the Wyoming Statutes Annotated and Chapter 3, Section 21 (k) and Section 23 of the Rules of the Wyoming Public Service Commission.

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

The increase in electric service utility rates is driven by a variety of factors since the last rate case, Docket No. 20004-117-ER-16 and Docket No. 20004-135-ER-18, which reflected the Tax Cuts and Jobs Act of 2017. This includes the continued investment, primarily in distribution facilities, 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 Wyoming electric operations. The Company proposes a total increase in revenues of $7,507,017 as shown on Statement L, page 4 based on a test year for the twelve months ended December 31, 2024, adjusted for known and measurable changes through year end 2025.

The proposed increase will affect approximately 17,600 electric customers in Wyoming. The proposed change in rates will affect customer classes by the following amounts and percentages:

Class	Amount	Increase
Residential	$4,546,347	26.00%
Small General Service	1,649,529	30.74%
Large General Service	1,128,286	15.15%
Irrigation Service	166,798	40.10%
Lighting	16,057	15.81%
Total	$7,507,017	24.36%

The Company also proposes an updated base cost of power supply based on its pro forma costs.

In accordance with Chapter 3, Section 23 of the Rules of the Wyoming Public Service Commission, included herein is a second set of the affected tariffs on which Montana-Dakota has indicated the revisions requested by lining through the existing language which the Company proposes to delete and underlining the new proposed language.

The Company will comply with Chapter 3, Section 21 of the Rules of the Wyoming Public Service Commission by posting a Notice of the proposed rates, as shown on Attachment A, in each of its business offices in its electric service territory. The proposed tariff sheets will be available in each business office and will be posted on the Company's website. The Notice to be posted for thirty days after these rates have been approved and placed in effect is included as Attachment B. A Report of Tariff change is provided as Attachment C.

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

- The Application including:
  - Appendix A – Current Rate Schedules
  - Appendix B - Proposed Final Rate Schedules including a redlined version of tariffs denoting proposed changes
- Prefiled Direct Testimony and Exhibits in support of the Application
- Supporting Statements and Workpapers

Please refer all inquiries regarding this filing to:

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

Please send copies of all inquiries, correspondence, and pleadings to:

Bruce S. Asay
Attorney
Associated Legal Group, LLC
1812 Pebrican Ave
Cheyenne, WY 82001
basay@associatedlegal.com

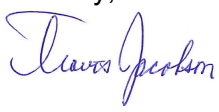
Allison Waldon
Senior Attorney
MDU Resources Group Inc.
P.O. Box 5650
Bismarck, ND 58506-5650
allison.waldon@mduresources.com

In addition, Montana-Dakota requests that all data requests regarding this Application be sent in Microsoft Word format by email to travis.jacobson@mdu.com.

Montana-Dakota will comply with Section 37-2-125(a) of the Wyoming Statutes and include the $5.00 filing associated with this filing when the Company is invoiced by the Commission. The invoice will include the filing fees associated with all the Company's electric filings submitted in 2025. An itemized list of all filing fees paid will be included with the check submitted and will include the docket number assigned hereto.

The Company is providing one hard copy of this letter of transmittal, application, tariffs, prefiled direct testimonies, statements, and information in support thereof to the Wyoming Public Service Commission. These documents are also filed electronically on the Commission's docket management system.

Sincerely,



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

Enclosures

cc: Anthony Ornelas, Wyoming Office of Consumer Advocate

CERTIFICATE OF SERVICE

I certify that on the 30th day of June 2025, a true and accurate copy of Montana-Dakota Utilities Co.'s application to increase its retail electric service utility rates in Wyoming has been electronically filed with the Wyoming Public Service Commission and served by mail and/or email to the following:

John Burbridge
Secretary & Chief Counsel
Wyoming Public Service Commission
Hansen Building, Suite 300
2515 Warren Avenue
Cheyenne, WY 82002
john.burbridge@wyo.gov

Anthony Ornelas
Wyoming Office of Consumer Advocate
Hansen Building
2515 Warren Ave Suite 304
Cheyenne, WY 82002
anthony.ornelas@wyo.gov

Bruce S. Asay
Attorney
Associated Legal Group, LLC
1812 Pebrican Ave
Cheyenne, WY 82001
basay@associatedlegal.com

Allison Waldon
Senior Attorney
MDU Resources Group Inc.
P.O. Box 5650
Bismarck, ND 58506-5650
allison.waldon@mduresources.com

/s/ Parker Oswald
parker.oswald@mdu.com
Regulatory Analyst
Montana-Dakota Utilities Co.

On June 30, 2025
Montana-Dakota Utilities Co.
filed with the Wyoming Public Service Commission revised electric rates affecting Montana-Dakota Utilities Co.'s electric sales customers in Wyoming.

The Wyoming Public Service Commission approved revised electric rates which affect Montana-Dakota Utilities Co.'s electric sales customers in Wyoming.

Report of Tariff Change

Name of Utility: Montana-Dakota Utilities Co.
Main Office Address: 400 North Fourth Street, Bismarck, ND 58501

Electric - All Classes
(Class of Service)

Tariff P.S.C. WY No. 2 Original Revised Sheet Nos. 1, 3
4, 6, 10, 15, 20, 30, 35, 37, 40, 43, 45, 50, 55, 60, 70, 72, 80, 90, 160
165, 167, 185, 190, 191, 200

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

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

Approximate reduction in revenue……..... $

Approximate increase in revenue……..... $ 7,507,017

Points Affected	Estimated number of customers whose cost of service will be:		
	Reduced	Increased	Unchanged
All		17,600	

Remarks:

Reporting Utility: Montana-Dakota Utilities Co.

By: Travis R. Jacobson, Vice President of Regulatory Affairs

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR APPROVAL OF A GENERAL RATE INCREASE IN ITS RETAIL ELECTRIC SERVICE UTILITY RATES	)))))	DOCKET NO. 20004-___-ER-25

APPLICATION

Montana-Dakota Utilities Co., (hereinafter referred to as Montana-Dakota, Applicant, or Company) submits this Application to the Wyoming Public Service Commission for approval of a general rate increase in its retail electric service utility rates in Wyoming. The Applicant in the above-entitled proceeding respectfully submits the following Application, 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 Wyoming as a foreign corporation and that it is doing business in the State of Wyoming as a public utility.

II.

The Company's Certificate of Incorporation and Amendments thereto have previously been filed with the Wyoming 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.

WYOMING ELECTRIC 2025 - CURRENT TARIFFS

W.P.S.C. Tariff No. 1	Description	Rate
Original Title Sheet	Title Sheet	
2nd Revised Sheet No. 1	Table of Contents	
Original Sheet No. 3	Communities Served	
8th Revised Sheet No. 4	Rate Summary Sheet	
15th Revised Sheet No. 5	Rate Summary Sheet	
1st Revised Sheet No. 6	Residential Electric Service	10
2nd Revised Sheet No. 10	Special Residential Controlled Electric Service	11
Original Sheet Nos. 11-12	Special Residential Controlled Electric Service	11
8th Revised Sheet No. 15	Renewable Energy Rider	15
1st Revised Sheet No. 16	Renewable Energy Rider	15
1st Revised Sheet Nos. 20-21	Small General Electric Service	20
Original Sheet No. 22	Small General Electric Service	20
2nd Revised Sheet No. 25	Special General Controlled Electric Service	22
Original Sheet Nos. 26-27	Special General Controlled Electric Service	22
1st Revised Sheet No. 30	Outdoor Lighting Service	24
Original Sheet No. 31	Outdoor Lighting Service	24
1st Revised Sheet No. 35	Irrigation Power Service	25
Original Sheet No. 36	Irrigation Power Service	25
1st Revised Sheet No. 37	Irrigation Power Service – Optional Time of Day	26
Original Sheet No. 38	Irrigation Power Service – Optional Time of Day	26
1st Revised Sheet No. 40	Large Power Standby Service	37
Original Sheet Nos. 41-42	Large Power Standby Service	37
1st Revised Sheet No. 45	Large General Electric Service	39
Original Sheet Nos. 46-47	Large General Electric Service	39
1st Revised Sheet No. 50	Municipal Lighting Service	41
Original Sheet No. 51	Municipal Lighting Service	41
1st Revised Sheet No. 55	Power Supply Cost Adjustment	50
Original Sheet Nos. 56-57	Power Supply Cost Adjustment	50

7th Revised Sheet Nos. 58-59	Power Supply Cost Adjustment	50
7th Revised Sheet No. 70	Parallel Generation	57
1st Revised Sheet No. 71	Parallel Generation	57
1st Revised Sheet Nos. 72-73	Net Metering Service	58
Original Sheet No. 74	Net Metering Service	58
Original Sheet Nos. 80-82	Parallel Generation General Rules	59
Original Sheet Nos. 90-117	Conditions of Service	100
1st Revised Sheet Nos. 118-119	Conditions of Service	100
Original Sheet Nos. 120-143	Conditions of Service	100
Original Sheet Nos. 160-162	Electric Extension Policy	104
Original Sheet No. 165	Dark Sky Lighting Service	105
Original Sheet Nos. 167-170	Service Interruption Reporting Plan	106
Original Sheet Nos. 185-189	Electric Meter Testing Program	115
1st Revised Sheet No. 190	AutoPay Plan	122
Original Sheet Nos. 200-201	Balanced Billing Plan	125

V.

Montana-Dakota respectfully hereby files the following described proposed rate schedules for electric service, copies attached hereto as Appendix B, of which Montana-Dakota proposes to be approved on a final basis in this Docket.

WYOMING ELECTRIC 2025 - PROPOSED TARIFFS

W.P.S.C. Tariff No. 2	Description	Rate
Original Title Sheet	Title Sheet	
Original Sheet No. 1	Table of Contents	
Original Sheet No. 3	Communities Served	
Original Sheet Nos. 4-4.1	Rate Summary Sheet	
Original Sheet No. 6	Residential Electric Service	10
Original Sheet Nos. 10-10.2	Special Residential Controlled Electric Service	11
Original Sheet Nos. 15-15.1	Renewable Energy Rider	15
Original Sheet Nos. 20-20.2	Small General Electric Service	20
Original Sheet Nos. 30-30.4	Outdoor Lighting Service	24
Original Sheet Nos. 35-35.1	Irrigation Power Service	25
Original Sheet Nos. 37-37.1	Irrigation Power Service – Optional Time of Day	26
Original Sheet Nos. 40-40.2	Large Power Standby Service	37
Original Sheet Nos. 43-43.2	Interruptible Large Power Demand Response	38
Original Sheet Nos. 45-45.2	Large General Electric Service	39
Original Sheet Nos. 50-50.1	Public Lighting Service	41
Original Sheet Nos. 55-55.4	Power Supply Cost Adjustment	50
Original Sheet Nos. 60-60.1	Reliability and Safety Infrastructure Rider	55

Original Sheet Nos. 70-70.1	Parallel Generation	57
Original Sheet Nos. 72-72.2	Net Metering Service	58
Original Sheet Nos. 80-80.2	Parallel Generation General Rules	59
Original Sheet Nos. 90-90.53	Conditions of Service	100
Original Sheet Nos. 160-160.2	Electric Extension Policy	104
Original Sheet No. 165	Dark Sky Lighting Service	105
Original Sheet Nos. 167-167.3	Service Interruption Reporting Plan	106
Original Sheet Nos. 185-185.4	Electric Meter Testing Program	115
Original Sheet No. 190	AutoPay Plan	122
Original Sheet Nos. 191-191.1	Summary Billing Plan	123
Original Sheet Nos. 200-200.1	Balanced Billing Plan	125

VI.

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

VII.

The new rates contained herein will provide additional revenues in the annual amount of $7,507,017 based a test year for the twelve months ended December 31, 2024, adjustment for known and measurable changes through year end 2025, for electric service rendered to customers in Wyoming. This request for additional revenue amounts to a 24.36 percent increase over current electric service utility rates.

VIII.

That Montana-Dakota will prove by competent evidence that existing rates are unjust, unreasonable, and not compensatory, and that said rate schedules should be increased as requested herein. Filed concurrently with this Application and its Appendices are supporting Statements, 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.

This Application is submitted in accordance with the provisions of Wyoming Statutes Title 37, Chapters 2 and 3 of the rules and regulations promulgated by the Public Service Commission of Wyoming.

WHEREFORE, by this Application, Montana-Dakota Utilities Co. respectfully requests that the Public Service Commission of Wyoming:

1. 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 $7,507,017 to be effective upon final disposition of this docket;

2. Expedite any hearing which the Commission deems necessary to determine the propriety of Applicant's proposed rate schedules set forth herein, and issue its final order establishing the rates set forth herein; and

3. Grant such other and additional relief as the Commission shall deem just and proper.

Respectfully submitted this 30th day of June 2025.

MONTANA-DAKOTA UTILITIES CO.

By _____

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

Montana-Dakota Utilities Co.

Wyoming Electric Tariffs - Current

Docket No. 20004-___-ER-25

Appendix A

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Title Sheet

TITLE SHEET

WYOMING P.S.C. TARIFF NO. 1
Including
Schedule of Rates for Electric Service
and
Rules

OF

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

400 N 4th Street

BISMARCK, NORTH DAKOTA 58501

Filed with the

WYOMING PUBLIC SERVICE COMMISSION

Date Filed:	January 4, 2019	**Effective Date:**	Service rendered on and after January 1, 2019
Issued By:	Tamie A. Aberle Director – Regulatory Affairs	**Docket No.:**	20004-128-EA-18

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
2nd Revised Sheet No. 1
Canceling 1st Revised Sheet No. 1

TABLE OF CONTENTS

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 3

COMMUNITIES SERVED

COMMUNITIES SERVED

Acme	Ranchester
Big Horn	*Sheridan
Dayton	Story

*Designates District Office

Montana-Dakota Sheridan District Office
2324 Dry Ranch Road
Sheridan, WY 82801
1.800.638.3278

Date Filed:	January 4, 2019	**Effective Date:**	Service rendered on and after January 1, 2019
Issued By:	Tamie A. Aberle Director – Regulatory Affairs	**Docket No.:**	20004-128-EA-18

Montana-Dakota Utilities Co.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
8th Revised Sheet No. 4
Canceling 7th Revised Sheet No. 4

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Demand Charge	Charge Per Kwh	PSCA Per Kwh 1/	Total Per Kwh
Residential Rate 10	6	$0.769 per day				
Energy Charge:						
First 1,000 Kwh per month				$0.04299	$0.05127	$0.09426
Over 1,000 Kwh per month				$0.06171	$0.05127	$0.11298
Special Residential Controlled Electric Service Rate 11	10	$0.167 per day				
Energy Charge:				$0.02089	$0.05127	$0.07216
Small General Electric Service Rate 20	20					
Demand Metered		$0.923 per day				
Primary Service:						
Demand Charge:						
First 10 Kw or less of billing demand			$5.15 per Kw			
Over 10 Kw per month of billing demand			$9.83 per Kw			
Energy Charge:				$0.02221	$0.04546	$0.06767
Secondary Service:						
Demand Charge:						
First 10 Kw or less of billing demand			$5.62 per Kw			
Over 10 Kw per month of billing demand			$10.30 per Kw			
Energy Charge:				$0.01968	$0.05127	$0.07095
Non Demand		$0.923 per day				
Energy Charge:				$0.02526	$0.05127	$0.07653
Special General Controlled Electric Service Rate 22	25	$0.215 per day				
Energy Charge:				$0.01998	$0.05127	$0.07125
Outdoor Lighting Service Rate 24	30					
Energy Charge:				$0.02531	$0.05127	$0.07658
Irrigation Power Service Rate 25	35	$1.54 per day				
Demand Charge:			$6.55 per Kw			
Energy Charge:				$0.02257	$0.05127	$0.07384
Irrigation Power Service Optional Time of Day Rate 26	37	$1.54 per day				
Demand Charge:						
On-Peak Demand:			$7.77 per Kw			
Off-Peak Demand:			$2.81 per Kw			
Energy Charge:				$0.03850	$0.05127	$0.08977

1/ Sheet No. 58

Date Filed: February 28, 2025

Issued By: Travis R. Jacobson
Vice President - Regulatory Affairs

Effective Date: Effective with service rendered on and after May 1, 2025

Docket No: 20004-170-EM-24
Record No. 17767

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
15th Revised Sheet No. 5
Canceling 14th Revised Sheet No. 5

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Demand Charge	Charge Per Kwh	PSCA Per Kwh 1/	Total Per Kwh
Large Power Standby Service						
Rate 37	40					
Primary Serivce:						
Contract Demand Charge:		$150.00 per month	$11.73 per Kw			
Energy Charge:				$0.01129	$0.04546	$0.05675
Secondary Service:						
Contract Demand Charge:		$66.00 per month	$12.20 per Kw			
Energy Charge:				$0.00478	$0.05127	$0.05605
Large General Electric Service						
Rate 39	45					
Primary Service		$150.00 per month				
Demand Charge:			$11.23 per Kw			
Energy Charge:				$0.01129	$0.04546	$0.05675
Secondary Service:		$66.00 per month				
Demand Charge:			$11.70 per Kw			
Energy Charge:				$0.00478	$0.05127	$0.05605
Municipal Lighting Service						
Rate 41	50					
Energy Charge:				$0.05507	$0.05127	$0.10634
Parallel Generation Rate 57	70					
Partial Requirement:						
Single Phase:		$3.30 per month				
Three Phase:		$9.34 per month				
Energy Payment:				$0.03448	Not Applicable	$0.03448
Parallel Generation:						
Single Phase:		$13.68 per month				
Three Phase:		$17.25 per month				
Capacity Payment			$8.29 per Kw			
Energy Payment:				$0.03448	Not Applicable	$0.03448

1/ Sheet No. 58

Date Filed: May 23, 2025

Issued By: Travis R. Jacobson
Vice President - Regulatory Affairs

Effective Date: Service rendered on and after June 1, 2025

Docket No: 20004-171-ET-25
Record No. 17778

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 6
Canceling Original Sheet No. 6

RESIDENTIAL ELECTRIC SERVICE
Rate 10

AVAILABILITY:

In all communities served for single-phase residential electric service through one meter in a single private residence for all domestic uses.

RATE:

Basic Service Charge:	$0.769 per day
Energy Charge:	
First 1,000 Kwh per month	4.299¢ per Kwh
Over 1,000 Kwh per month	6.171¢ per Kwh
Power Supply Cost Adjustment:	Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

MINIMUM BILL:

Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
2nd Revised Sheet No. 10
Canceling 1st Revised Sheet No. 10

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11 (CLOSED TO NEW CUSTOMERS)

AVAILABILITY:

In all communities served for single-phase residential electric service customers who operate Company approved interruptible electric space heating equipment so arranged to allow remote operation by the Company and subject to the Company's ability to control such equipment. This rate schedule is restricted to active services installed on a customer's premise on or before August 2, 2022.

Controlled electric water heating service is also available under this rate in conjunction with controlled space heating. The customer's primary source of space heating shall be electric and the customer shall be responsible for providing a secondary source of space heating. The main energy used in backup systems cannot be firm electric service. Domestic uses other than controlled space heating and controlled water heating will be served under Residential Electric Service Rate 10.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving water heating and space heating facilities with no provision for connecting other loads thereto. The customer's secondary system controls, circulating fans and pumps and all other alternate fuel related equipment shall be served as uncontrolled load. Unless otherwise specified by the Company, the point of delivery and service voltage for this service shall be the same as for the customer's other electric service.

RATE:

Basic Service Charge:	$0.167 per day
Energy Charge:	2.089¢ per Kwh
Power Supply Cost Adjustment:	Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

MINIMUM BILL:

Basic Service Charge.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 11

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

CONTRACT TERMS:

The customer agrees to contract for service under the Special Residential Controlled Electric Service rate for a minimum period of one year. If the customer fails to continue service for the initial annual period, the customer will be billed for the difference between the customer's actual billing under Rate 11 and what would have been billed under Rate 10. At the end of a one year period, the customer will have the option of remaining under the Special Residential Controlled Electric Service rate or of returning to the Residential Electric Service rate.

GENERAL TERMS AND CONDITIONS:

1. Electric space and water heating equipment shall be designed to operate at a nominal voltage of 208, 240, or 277 volts, shall be separately metered and separately circuited, shall be permanently installed and the electric heating equipment shall be the principal source of space heating.

2. All installations must meet the minimum standards of the National Electrical Code so that the equipment will operate in a satisfactory manner and not interfere with other operations of the Company's system. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations for heating to make sure their equipment, insulation and building construction will meet requirements and receive adequate service.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 12

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11

3. The customer must connect the interruptible electrical circuit(s) so as to allow interruptions through a Company owned contactor(s). A maximum of two contactors shall be provided by Company up to a maximum rating of 5 amps for one and 30 amps for the other. The customer must wire into a connection point designated by Company to allow installation of control equipment by Company. The customer must provide a continuous 240 volt AC power source at the connection point for operation of the Company's control system.

4. The Company recommends that the installed capacity of electric water heating equipment be sufficient to provide the required volume of hot water giving consideration to the interruptions to be experienced and to permit maximum utilization of the rate for the benefit of the customer.

5. Service hereunder shall be available at the time control equipment is actually installed by the Company.

6. The Company shall not be liable for loss or damage caused by interruption of service.

7. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
8th Revised Sheet No. 15
Canceling 7th Revised Sheet No. 15

RENEWABLE ENERGY RIDER
Rate 15

AVAILABILITY:
In all communities served by the Company in the State of Wyoming. The Renewable Energy Rider is available on an optional basis to customers receiving service under the Company's Electric Service Rate Schedules.

CHARGE PER BLOCK:

One (1) Block:	$0.01 per month

One Block equals 100 Kwh of Renewable Energy Credit purchases.

MONTHLY BILL:
The Monthly Bill shall be the number of Blocks the customer has agreed to purchase multiplied by the Charge per Block. The Monthly Bill is in addition to all other charges contained in the customer's applicable rate schedule. The Monthly Bill shall be applied to the customer's billing regardless of actual energy consumption.

RENEWABLE ENERGY CREDIT:
A Renewable Energy Credit represents the intangible environmental attributes associated with producing one MWh of electricity from a renewable resource such as wind, solar or biomass. The Company will purchase Renewable Energy Credits as needed to match the number of Blocks purchased under this rate schedule. One Renewable Energy Credit equals 1,000 Kwh (1 MWh) of electricity from a renewable resource. Each Block is equivalent to one-tenth (1/10) of a Renewable Energy Credit.

GENERAL TERMS AND CONDITIONS:

1. Customers may apply for this rate any time during the year.

2. The Company will purchase Renewable Energy Credits to match purchases under this rate schedule. Due to timing differences, the purchase of Renewable Energy Credits may not directly correspond to customer purchases in an individual 12 month period.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 16
Canceling Original Sheet No. 16

RENEWABLE ENERGY RIDER
Rate 15

3. All funds collected and expenses associated with this program will be separately identified and tracked. Interest shall be credited in the case of net over collections at one-twelfth of the Commission's Authorized Interest Rate specified in accordance with Chapter 1, Section 2(a)(xv) of the Wyoming Public Service Commission's Rules. The Charge per Block is subject to change on an annual basis.

4. The commitment to purchase Blocks under this Rider will be for a minimum of a one year period and will continue on a monthly basis thereafter until the customer provides notice to either change or end participation. Requests for early withdrawal due to extenuating circumstances will be considered.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 20
Canceling Original Sheet No. 20

SMALL GENERAL ELECTRIC SERVICE
Rate 20

AVAILABILITY:

In all communities served for all types of general electric service with billing demands of 50 kilowatts or less, except customers covered by special contracts, or other rate schedules applicable to specific services. The customer's wiring must be so arranged that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

RATE:

Demand Metered Basic Service Charge: $0.923 per day

Primary Service:

Demand Charge:

First	10 Kw or less of billing demand	$5.15 per Kw
Over	10 Kw per month of billing demand	$9.83 per Kw

Energy Charge: 2.221¢ per Kwh

Power Supply Cost Adjustment:
Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

Secondary Service:

Demand Charge:

First	10 Kw or less of billing demand	$ 5.62 per Kw
Over	10 Kw per month of billing demand	$10.30 per Kw

Energy Charge: 1.968¢ per Kwh

Power Supply Cost Adjustment:
Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

Non Demand Metered Basic Service Charge: $0.923 per day

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 21
Canceling Original Sheet No. 21

SMALL GENERAL ELECTRIC SERVICE
Rate 20

Energy Charge: 2.526¢ per Kwh

Power Supply Cost Adjustment:
Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

MINIMUM BILL:
Basic Service Charge.

PAYMENT:
Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:
Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

DETERMINATION OF BILLING DEMAND:
The demand in kilowatts for billing purposes shall be the maximum 15-minute measured demand in the current month. Demand will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:
The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

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

State of Wyoming
Electric Rate Schedule

SMALL GENERAL ELECTRIC SERVICE
Rate 20

GENERAL TERMS AND CONDITIONS:

1. All installations must meet the minimum standards of the National Electrical Code so that the equipment will operate in a satisfactory manner, and not interfere with other operations of the Company's system. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. At its discretion, the Company may install a demand meter on any customer's service whose average monthly usage exceeds 4,000 Kwh or who has an average peak demand greater than 10 Kw in any given twelve month period.

3. The primary service rate is applicable to customers that own their own transformers, related equipment, and distribution facilities downstream of the meter, satisfactory to the Company so customers can receive service and be metered at primary voltages of 2,400 volts or greater.

4. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
2nd Revised Sheet No. 25
Canceling 1st Revised Sheet No. 25

SPECIAL GENERAL CONTROLLED
ELECTRIC SERVICE Rate 22 (CLOSED TO NEW CUSTOMERS)

AVAILABILITY:

In all communities served for small and large general electric service customers (as defined in the availability sections of Small General Electric Service Rate 20 and Large General Electric Service Rate 39) who operate Company approved controlled electric equipment so arranged to allow remote operation by the Company and subject to the Company's ability to control such equipment. This rate schedule is restricted to active services installed on a customer's premise on or before August 2, 2022.

Company approved controlled electric equipment shall constitute equipment associated with loads directly contributing to the Company's system peak(s) as determined and accepted by the Company. The customer shall be responsible for providing alternate energy backup systems or equipment as required. The main energy used in backup systems cannot be firm electric service.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving approved controlled facilities with no provision for connecting other loads thereto. The customer's backup system controls or equipment controls shall be served as firm load. Unless otherwise specified by the Company, the point of delivery and service voltage for this service shall be the same as for any other electric service provided to the customers.

RATE:

Basic Service Charge:	$0.215 per day
Energy Charge:	1.998¢ per Kwh
Power Supply Cost Adjustment:	Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

MINIMUM BILL:

Basic Service Charge.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 26

SPECIAL GENERAL CONTROLLED ELECTRIC SERVICE Rate 22

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

CONTRACT TERMS:

The customer agrees to contract for service under the Special General Controlled Electric Service rate for a minimum period of one year. If the customer fails to continue service for the initial annual period, the customer will be billed for the difference between the customer's actual billing under Rate 22 and what would have been billed under the otherwise applicable General Service rate. At the end of a one year period, the customer will have the option of remaining under the Special General Controlled Electric Service rate or of returning to the otherwise applicable General Service rate.

GENERAL TERMS AND CONDITIONS:

1. Electric equipment shall be designed to operate at a nominal voltage of 208, 240, 277, or 480 volts, shall be separately metered and separately circuited, and shall be permanently installed.

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

State of Wyoming
Electric Rate Schedule

SPECIAL GENERAL CONTROLLED ELECTRIC SERVICE Rate 22

2. All installations must meet the minimum standards of the National Electrical Code so that the equipment will operate in a satisfactory manner and not interfere with other operations of the Company's system. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations for heating to make sure their equipment, insulation and building construction will meet requirements and receive adequate service.

3. The customer must connect the controlled electrical circuit(s) so as to allow interruptions through a Company owned contactor(s). A maximum of two contactors shall be provided by Company up to a maximum rating of 5 amps for one and 30 amps for the other. The customer must wire into a connection point designated by the Company to allow installation of control equipment by Company. The customer must provide a continuous 240 volt AC power source at the connection point for operation of the Company's control system.

4. The Company recommends that the installed capacity of electric water heating equipment be sufficient to provide the required volume of hot water giving consideration to the interruptions to be experienced and to permit maximum utilization of the rate for the benefit of the customer.

5. Service hereunder shall be available at the time control equipment is actually installed by the Company.

6. The Company shall not be liable for loss or damage caused by interruption of service.

7. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 30
Canceling Original Sheet No. 30

OUTDOOR LIGHTING SERVICE
Rate 24

AVAILABILITY:

For all outdoor lighting including flood lights, billboard lighting and metallic vapor yard lights in all communities served. Lighting equipment may be Company-owned or customer-owned.

RATE:

Energy Charge:

2.531¢ per Kwh computed according to the total rated capacity of the units in use.

Power Supply Cost Adjustment:

Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

1. When service is not metered, the bill shall be computed on an annual basis, utilizing the minimum service requirement of 4,000 hours annually, and one-twelfth shall be payable each month.

2. Applicable to Company-owned facilities:
   a. The Company will install, own and operate the flood light(s), and yardlight(s) including a suitable reflector, bracket for mounting and automatic device to control operating hours set to operate from dusk to dawn.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 31

OUTDOOR LIGHTING SERVICE
Rate 24

b. The Company will convert mercury vapor light units to high pressure sodium upon failure of existing mercury vapor units.

c. The light may be mounted on existing poles owned or controlled by the Company. The Company will furnish a 35 foot pole(s) for flood lights and a 30 foot pole(s) for yardlights at the customer's request at a separate rental rate if a special setting is required. If the customer chooses, the light may be installed on a pole owned by the customer or other mounting point suitable for installation of the light. The conductors will be extended 100 feet per unit free of charge, but the customer shall pay for the extra cost of extensions of more than 100 feet per unit.

d. In addition to the energy charge, a monthly rental charge shall be rendered for each unit installed.

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 35
Canceling Original Sheet No. 35

IRRIGATION POWER SERVICE
Rate 25

AVAILABILITY:

For all irrigation power service, except customers choosing the Irrigation Power Service – Optional Time of Day Rate 26.

RATE:

Basic Service Charge:	$1.54 per day
Demand Charge:	$6.55 per Kw
Energy Charge:	2.257¢ per Kwh

Power Supply Cost Adjustment:
Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

MINIMUM BILL: Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the maximum 15-minute measured demand in the current month. Demand will be determined to the nearest one-tenth kilowatt.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 36

IRRIGATION POWER SERVICE
Rate 25

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. Individual motors having a rating in excess of 10 horsepower must be three-phase. All wiring and other facilities beyond the point of metering shall be owned, operated, and maintained by the customer.

2. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 37
Canceling Original Sheet No. 37

IRRIGATION POWER SERVICE – OPTIONAL TIME OF DAY
Rate 26

AVAILABILITY:

For irrigation power service where customer chooses the optional time differentiated schedule for a minimum period of 12 months.

RATE:

Basic Service Charge: $1.54 per day

Demand Charge:

On-Peak Demand: $ 7.77 per Kw
Demand measured during peak hours designated as 4 p.m. to 6 p.m. local time Monday through Friday.

Off-Peak Demand: $ 2.81 per Kw
Demand measured during all hours not covered by the on-peak rating period.

Energy Charge: 3.850¢ per Kwh

Power Supply Cost Adjustment:

Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

MINIMUM BILL: Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 38

IRRIGATION POWER SERVICE – OPTIONAL TIME OF DAY
Rate 26

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the maximum 15-minute measured demand in the off-peak period and the maximum 15-minute measured demand in the on-peak period in the current month. Demand will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. Individual motors having a rating in excess of 10 horsepower must be three-phase. All wiring and other facilities beyond the point of metering shall be owned, operated, and maintained by the customer.

2. A customer choosing the optional time of day schedule shall remain on that schedule for a twelve month period.

3.. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 40
Canceling Original Sheet No. 40

LARGE POWER STANDBY SERVICE
Rate 37

AVAILABILITY:

This rate is applicable for power and lighting requirements of customers having their own generating facilities desiring standby power of 200 kilowatts or more through a permanent connection to be used in the event of failure of such generating facilities, or for use during the maintenance and overhaul of such facilities.

RATE:

Primary Service:

Basic Service Charge:	$150.00 per month
Contract Demand Charge:	$11.73 per Kw
Energy Charge:	1.129¢ per Kwh

Power Supply Cost Adjustment:
Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

Secondary Service:

Basic Service Charge:	$66.00 per month
Contract Demand Charge:	$12.20 per Kw
Energy Charge:	0.478¢ per Kwh

Power Supply Cost Adjustment:
Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

MINIMUM BILL:

Basic Service Charge plus Contract Demand Charge (Contract Demand minimum).

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

State of Wyoming
Electric Rate Schedule

LARGE POWER STANDBY SERVICE
Rate 37

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

DETERMINATION OF CONTRACT DEMAND:

The demand in kilowatts for billing purposes shall be the greater of either the maximum 15-minute measured demand in the current month or the contract demand in kilowatts. Measured demand will be determined to the nearest one-tenth kilowatt. The Company will require the customer to contract for additional standby and supplementary capacity if the customer exceeds the contract demand in any one month. Such measured demand shall become the new contract demand commencing with the month in which measured and thereafter for the eleven succeeding months, after which the customer and Company will redetermine full service requirements.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

CONTRACT TERMS:

The customer agrees to contract for service under the Large Power Standby Service rate for a minimum period of one year. If the customer fails to continue service for the initial annual period, the customer will be billed for the difference

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

State of Wyoming
Electric Rate Schedule

LARGE POWER STANDBY SERVICE
Rate 37

between the customer's actual billing under Rate 37 and what would have been billed under Rate 39.

GENERAL TERMS AND CONDITIONS:

1. The customer will contract for capacity adequate to supply the entire electrical requirements for which the Company's service may be used. Contract demand will be no less than what the Company will be required to supply in case of customer equipment malfunction.

2. No customer may connect an independent source of power in parallel with the Company's system without prior written consent of the Company. Any customer desiring to generate in parallel shall execute a contract with the Company that contains terms and provisions regarding metering, billing, technical, and operating parameters for the customer's independent source of power.

3. The customer shall be subject to charges for interconnection costs, as defined in the Energy Sales Agreement.

4. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 45
Canceling Original Sheet No. 45

LARGE GENERAL ELECTRIC SERVICE
Rate 39

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 kilowatts of billing demand, except customers covered by special contracts. The customer's wiring must be so arranged that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

RATE:

Primary Service:

Basic Service Charge:	$150.00 per month
Demand Charge:	$11.23 per Kw of billing demand
Energy Charge:	1.129¢ per Kwh

Power Supply Cost Adjustment:
Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

Secondary Service:

Basic Service Charge:	$66.00 per month
Demand Charge:	$11.70 per Kw of billing demand
Energy Charge:	0.478¢ per Kwh

Power Supply Cost Adjustment:
Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

MINIMUM BILL:

Basic Service Charge plus Demand Charge.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 46

LARGE GENERAL ELECTRIC SERVICE
Rate 39

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15-minute measured demand in the current month or 50 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to Conditions of Service Rate 100, Section 700.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 47

LARGE GENERAL ELECTRIC SERVICE
Rate 39

2. The primary service rate is applicable to customers that own their own transformers, related equipment, and distribution facilities downstream of the meter, satisfactory to the Company so customers can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 50
Canceling Original Sheet No. 50

MUNICIPAL LIGHTING SERVICE
Rate 41

AVAILABILITY:

Company-owned and municipally-owned street lighting systems in Sheridan, Dayton and Ranchester, Wyoming for street lighting purposes including streets, alleys and other public grounds.

RATE:

Energy Charge:	5.507¢ per Kwh for all energy used
Power Supply Cost Adjustment:	Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

1. When service is not metered, the bill shall be computed on an annual basis, utilizing the minimum service requirement of 4,000 hours annually, and one-twelfth shall be payable each month.

2. In Company-owned street lighting systems, a monthly rental charge shall be rendered in addition to the energy charge. The customer should consult with the Company for such costs.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 51

MUNICIPAL LIGHTING SERVICE
Rate 41

3. In Company-owned street lighting systems, the Company will maintain the facilities and change the light bulbs when notified by the municipality that they are burned out except when the facilities are damaged or destroyed by vandalism, malicious mischief by third parties, or willful negligence on the part of employees of the municipality. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the municipality for the cost of repair and replacement.

   The Company will convert mercury vapor light units to high pressure sodium upon failure of existing mercury vapor units.

4. In municipally-owned street lighting systems, an additional charge will be made to cover lamp replacements, materials and labor whenever such services are supplied by the Company.

5. Service will be provided all night every night in the year with a minimum service requirement of 4,000 hours annually, and must be covered by written contract.

6. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 55
Canceling Original Sheet No. 55

POWER SUPPLY COST ADJUSTMENT
Rate 50

1. APPLICABILITY:
   This rate schedule constitutes a Power Supply Cost Adjustment (PSCA) provision and specifies the procedure to be utilized to adjust the rates for fuel and purchased power sold under Montana-Dakota's rate schedules in order to reflect the recovery (refund) of the Power Supply Balancing Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:
   The effective date of the PSCA shall be service rendered on and after May 1 each year unless the Wyoming Public Service Commission (Commission) shall otherwise order. The Company will file an application with the Commission to implement the PSCA rate on an interim basis and, if approved by the Commission, the PSCA rate shall continue until a final order is issued by the Commission establishing an effective PSCA rate.

3. POWER SUPPLY COST ADJUSTMENT:
   a. The annual PSCA shall be calculated separately for primary service and secondary service and reflect changes in Montana-Dakota's cost of power supply as compared to the base cost of power supply established in a general rate case for each class.

   b. The cost of power supply shall be the sum of the approved costs incurred in obtaining fuel and purchased power supply for use by all customers served under retail sales rate schedules for the twelve month period ending December 31 each year.

   c. The cost of power supply shall include the following costs for fuel and purchased power supply:

      1. Fuel and fuel handling costs recorded in Account No. 501 and reagent costs recorded in Account 502;
      2. Demand, energy, ancillary services and transmission charges recorded in Account 555;
      3. Regional Marketing Administration expenses recorded in Account 575; and
      4. The cost of new or existing governmental impositions for electric generation plant emissions, including but not limited to $S0_2$ allowances, carbon taxes and/or carbon allowances and other governmental initiatives related to electric generation plant emissions. Prior to

including any new governmental impositions in the PSCA, the Company will receive approval from the Commission.

d. The base cost of power supply shall consist of all power supply costs established in a general rate case for primary and secondary service stated on a Kwh basis. The base cost of power supply established in Docket No. 20004-117-ER-16 is as follows:

Base Cost of Power Supply Expense	Primary	Secondary
Fuel	0.982¢	0.991¢
Purchased Power	2.157¢	2.423¢
Total	3.139¢	3.414¢

e. The calculation of the power supply cost adjustment is shown on Sheet No. 59.

4. POWER SUPPLY BALANCING ACCOUNT:
   a. Items to be included in the Power Supply Balancing Account are:
      1. Amounts under recovered or over recovered for fuel;
      2. Amounts under recovered or over recovered for purchased power supplies each month;
      3. Refunds received with respect to fuel and purchased power supply shall be credited to the Power Supply Balancing Account; and
      4. Interest on the net over or under collected balance in accordance with Subsection 4.b.4.

   b. The amount to be included in the Power Supply Balancing Account in order to reflect the items specified in Subsection 4.a.1-4 shall be calculated as follows:
      1. Montana-Dakota shall first determine each month the unit cost for that month's fuel cost and purchased power costs by PSCA class:

a. Fuel costs shall be allocated to each class based on sales volumes for the month adjusted for the applicable loss factor from the most recently approved general rate case; and

b. Purchased power energy shall be allocated to each class based on sales volumes for the month adjusted for the applicable loss factor from the most recently approved general rate case. Purchased power demand and transmission charges shall be allocated to each class based on the average and excess demand factor that will be updated annually.

2. Montana-Dakota shall then subtract from each month's unit cost (fuel and purchased power) the total cost in rates as set forth in Subsection 6:
   a. For fuel, the difference (which may be positive or negative) shall be multiplied by 85 percent and by the Kwh sold during that month under each applicable rate schedule. The resulting amounts shall be reflected in the Balancing Account (Account 182.3) for primary and secondary service; and
   b. For purchased power, the difference (which may be positive or negative) shall be multiplied by 95 percent and by the Kwh sold during that month under each applicable rate schedule. The resulting amounts shall be reflected in the Balancing Account for primary and secondary service.

3. The amounts in the Power Supply Balancing Account shall be decreased each month by an amount determined by multiplying the currently effective Surcharge Adjustment included in rates for that month by the Kwh sales during that month under each rate schedule. The amount in the account shall be increased in the event the adjustment is a negative amount.

4. The balance in Account 182.3, to which interest will apply, will be the balance at the end of the immediately preceding month. Interest shall be applied to the net over or under collected balance at one-twelfth of the

Commission's Authorized Interest Rate specified in Chapter 1, Section 2(a)(xv) of the Commission's Rules and recorded in Account 182.3.

The amount amortized each month shall be applied pro rata between the amounts in the Power Supply Balancing Account specified in Subsection 4.a.1. and 2. and the amount related to carrying charges specified in Subsection 4.a.

5. TIME AND MANNER OF FILING:
   a. Each application by Montana-Dakota shall be made by means of revised PSCA and rate schedule tariff sheets identifying the amounts of the adjustments and the resulting currently effective PSCA rates.

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

   c. The application shall be made 60 days prior to the implementation date of May 1 each year.

6. POWER SUPPLY COST ADJUSTMENT:
   The total power supply cost equals 4.546¢ per Kwh for the Primary Service PSCA rate class and 5.127¢ per Kwh for the Secondary Service PSCA rate class. The currently effective PSCA applied to each rate schedule and shown separately on the consumer bill is:

	Primary	Secondary
Base Cost of Power Supply	3.139¢	3.414¢
Power Supply Cost Adjustment	1.151	1.259
Power Supply Balancing Account Adjustment	0.256	0.454
Total PSCA	4.546¢	5.127¢

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
7th Revised Sheet No. 59
Canceling 6th Revised Sheet No. 59

POWER SUPPLY COST ADJUSTMENT
Rate 50

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - WYOMING
POWER SUPPLY COST ADJUSTMENT
TARIFF CALCULATION

	Total	Primary	Secondary
Fuel			
501.1 Fuel	$2,381,166.52	$203,216.92	$2,177,949.60
501.4 Fuel Handling	573.13	48.91	524.22
502.4 Reagents	420,150.55	35,857.09	384,293.46
Total Fuel	$2,801,890.20	$239,122.92	$2,562,767.28
kWh Sales	292,769,653	25,217,920	267,551,733
Cost per kWh		$0.00948	$0.00958
Base Cost of Fuel		0.00982	0.00991
Difference from Base		($0.00034)	($0.00033)
Total Change from Base	($96,866.16)	($8,574.09)	($88,292.07)
Amount to be recovered/(refunded) from customers (85%)		($7,287.98)	($75,048.26)
Purchased Power			
555.1 & 575 Energy	$5,154,621.70	$439,913.10	$4,714,708.60
555.6 Capacity	2,707,479.10	193,803.06	2,513,676.04
555.6 Transmission	2,921,019.58	209,088.42	2,711,931.16
Purchased Power	$10,783,120.38	$842,804.58	$9,940,315.80
kWh Sales	292,769,653	25,217,920	267,551,733
Cost per kWh		$0.03342	$0.03715
Base Cost of Purchased Power		0.02157	0.02423
Difference from Base		$0.01185	$0.01292
Total Change from Base	$3,755,600.74	$298,832.35	$3,456,768.39
Amount to be recovered/(refunded) from customers (95%)		$283,890.73	$3,283,929.97
Power Supply Balancing Account Adjustment			
Balance at 12/31/23		($6,127.38)	$673,055.26
(Over)/Under Recovery			
Fuel		($7,824.33)	($74,785.02)
Purchased Power		269,579.05	3,298,992.75
Less: Current Power Supply Cost Adjustment		166,228.91	1,845,193.21
Net		$95,525.81	$1,379,014.52
Amortization		46,698.06	926,285.41
Interest		(3,242.33)	13,496.79
Balance at 12/31/24		$39,458.04	$1,139,281.16
Estimated Amortization January-April 2025		($26,920.94)	($102,641.04)
Net Balance		$66,378.98	$1,241,922.20
Projected kWh Sales		25,976,000	273,405,000
Power Supply Cost Balancing Account Adjustment		$0.00256	$0.00454
Base Cost of Power Supply		$0.03139	$0.03414
Power Supply Cost Adjustment		0.01151	0.01259
Power Supply Cost Balancing Account Adjustment		0.00256	0.00454
Total PSCA		$0.04546	$0.05127

Date Filed: February 28, 2025

Issued By: Travis R. Jacobson
Vice President – Regulatory Affairs

Effective Date: Effective with service rendered on and after May 1, 2025

Docket No.: 20004-170-EM-24
Record No. 17767

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
7th Revised Sheet No. 70
Canceling 6th Revised Sheet No. 70

PARALLEL GENERATION
Rate 57

AVAILABILITY:

Available to (1) any single or three-phase electric service customer who generates electrical energy in excess of their total energy requirements and who has received qualifying status as a cogenerator or small power producer under Section 201 of the Public Utility Regulatory Policies Act of 1978, defined herein as Parallel Generation Customer, or (2) where the customer's intent is to primarily offset part or all of the customer's own electrical requirements, but whose generating facility exceeds the 25 Kw maximum allowed under Net Metering Rate 58, defined herein as Partial Requirements Customer (qualifying facilities).

RATE:

Service provided to such customers by the Company shall be billed at the appropriate rate, by class of customers (i.e., residential, commercial, etc.) that is currently on file with the Commission. Customers under this rate schedule will not be net metered.

Minimum Bill: Basic Service Charge.

Rates may be updated annually, in correlation with the Company's annual Power Supply Cost Adjustment filing.

Partial Requirements Customer:

Basic Service Charge:	
Single Phase:	$3.30 per month
Three Phase:	$9.34 per month
Energy Payment:	3.448¢ per Kwh Received

Parallel Generation Customer:

(1) For generating facilities rated at 100 Kw or Less

Basic Service Charge:	
Single Phase:	$13.68 per month
Three Phase:	$17.25 per month
Energy Payment:	3.448¢ per Kwh Received
Capacity Payment:	$8.29 per Kw Received per month

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

State of Wyoming
Electric Rate Schedule

PARALLEL GENERATION
Rate 57

Capacity payments will be made only to those qualifying facilities that actually contribute to a capacity savings to the Company by a reduction in the demand charges paid by the Company to Black Hills Power, Inc. under the terms of the contract between the Company and Black Hills Power, Inc. regarding the determination of the billing demand. The kilowatts used for determining any capacity payment by the Company shall be the kilowatts supplied by the qualifying facility at the time of the Company's monthly system peak demand.

(2) For generating facilities rated at 101 Kw and Greater

The Company will enter into individual agreements.

GENERAL TERMS AND CONDITIONS:

1. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

2. The customer shall, with prior written consent of the Company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.

3. Any changes made to the customer's generating facility that increases the capacity, included in the customer's Interconnection Agreement, must first be approved by Montana-Dakota prior to installation to ensure the continued safe and reliable operation of the Company's electric system. If the Company is not contacted, the Company reserves the right to disconnect the facility until the issue is resolved.

4. The foregoing schedule is subject to Rate 59 and Rates 100 and 104. Any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 72
Canceling Original Sheet No. 72

NET METERING SERVICE
Rate 58

AVAILABILITY:

Available to any customer that owns and operates a solar, wind, biomass or hydroelectric generating facility with a capacity of not more than 25 Kw that is located on the customer's premises and that is intended primarily to offset part or all of the customer's own electrical requirements. The generating facility must be interconnected and operated in parallel with the Company's existing transmission and distribution facilities. This service is offered in compliance with Wyoming Statutes §37-16-101 to 104.

APPLICABLITY:

Net Metering means measuring the difference between the electricity supplied by the Company and electricity generated by an eligible customer-generator and fed back to the electric grid over the applicable billing period.

RATE:

Basic Service Charge: The Basic Service Charge per the applicable standard service rate.

Energy Charge: If the energy supplied by the Company exceeds the customer generated energy, the energy charge (including the PSCA) per Kwh under the otherwise applicable standard service tariff shall be applied to the positive energy balance and charged to the customer.

If the energy supplied by the customer generator exceeds the amount of energy supplied by the Company, the net Kwh shall be credited to the customer's next monthly bill.

GENERAL TERMS AND CONDITIONS:

1. At the beginning of each calendar year, any Kwh credit balance accumulated during the previous year shall be purchased by the Company at the currently effective avoided cost rate (energy payment) applicable under Parallel Generation Rate 57.

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

State of Wyoming
Electric Rate Schedule

NET METERING SERVICE
Rate 58

2. The customer is responsible for all costs associated with its facility and is also responsible for all costs related to any modifications to the facility that may be required by the Company for purposes of safety and reliability.

3. A Net Metering facility shall meet all applicable safety and performance standards established by the National Electrical Code.

4. The customer is responsible, at their expense, for providing lockable switch equipment capable of isolating the net metering facility from the Company's system. Such equipment shall be approved by the Company and shall be accessible by the Company at all times.

5. A meter shall be installed between the parties to measure the flow of energy in each direction between the customer and Montana-Dakota. The customer shall be responsible for all expenses involved in purchasing and installing facilities necessary for the meter installation.

6. The customer shall enter into an Interconnection Agreement for Net Metering Service.

7. Any changes made to the customer's generating facility that increases the capacity, included in the customer's Interconnection Agreement, must first be approved by Montana-Dakota prior to installation to ensure the continued safe and reliable operation of the Company's electric system. If the Company is not contacted, the Company reserves the right to disconnect the facility until the issue is resolved.

    a. If the changes cause the generating facility's capacity to exceed the 25 Kw maximum allowed for under this rate schedule, the customer must enter into a new Interconnection Agreement under Parallel Generation Rate 57. Absent a new Interconnection Agreement, the Company reserves the right to disconnect the facility until the issue is resolved.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 74

NET METERING SERVICE
Rate 58

8. The foregoing schedule is subject to Rate 59 and Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 80

PARALLEL GENERATION GENERAL RULES
Rate 59

GENERAL RULES FOR PARALLEL GENERATION:

1. The interconnection between the utility and the qualifying facility will be limited to the service voltage and phases available at the qualifying facility. If different voltages or phases are required, the necessary changes will be provided by the qualifying facility.

2. The power factor and frequency of the qualifying facility shall be such as to not adversely affect the utility system. If corrective devices are required, they will be provided by the qualifying facility.

3. Fault protection equipment shall be provided by the qualifying facility. The utility and qualifying facility shall coordinate protective devices in order to limit damage to each system.

4. The qualifying facility's interconnection shall meet the requirements of local, state and federal codes.

5. The owner of the qualifying facility shall submit equipment specifications as requested by the utility prior to owner's installation of such equipment to assure compatibility and coordination with the utility system.

6. The owner of a qualifying facility will be requested to curtail, interrupt or reduce deliveries of electric energy, in order that the utility may construct, install, maintain, repair, replace, remove or inspect any of its equipment or any part of its system, or if it determines that curtailment, interruption or reduction of delivery is necessary because of safety, emergencies, forced outages or operating conditions on its system. Except in case of emergency, in order to minimize operating problems, the utility and qualifying facility shall give the other reasonable prior notice of any curtailment, interruption or reduction of delivery and its probable duration.

7. The Company reserves the right for periodic inspection of safety devices which are part of the interconnection. This would not affect the

responsibility of the qualifying facility to assure the operating safety of the equipment on its side of the interconnection point.

8. The Company reserves the right to disconnect any facility that has interconnected without utility authorization.

9. The Company has the right to disconnect and lock-out a qualifying facility's generating equipment with due notice whenever it has been determined that harmonics are being produced or other factors are present which would interfere with communications or otherwise cause degradation of service to other customers. If, in the judgment of the utility, an unsafe condition is created on the utility system by the operation of the qualifying facility, the utility shall have the right to disconnect the facility until the cause of such condition is eliminated.

10. In the event of a utility system outage or interruption of service, a qualifying facility's generator shall be capable of automatically disconnecting itself to prevent the utility's line from being energized. Also, a qualifying facility's system shall not be capable of energizing the utility's line when that line is deenergized.

11. A manually operated generator disconnect switch, provided by the owner of a qualifying facility, shall be accessible to utility personnel at all times. Such a switch would be used whether or not the owner is present to remove the qualifying facility's generator from the line in an emergency situation as determined by utility system conditions.

12. The owner of a qualifying facility shall maintain operating communications with the utility for facilities with a capacity of more than 100 Kw or as requested. Operating communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances and load reports.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 82

PARALLEL GENERATION GENERAL RULES
Rate 59

13. All necessary rights-of-way and easements to install, operate, maintain, replace and remove utility facilities, including adequate access rights, are to be furnished by the owner of the qualifying facility on owner's property.

14. The metering shall be adequate to measure energy, or energy and capacity, from the qualifying facility to the utility, from the utility to the qualifying facility, and, if necessary, adequate to determine the time at which energy is transferred from one party to another.

15. Interconnection costs shall be on an actual cost basis for all costs that are in excess of the costs that the utility would have incurred if it had not engaged in interconnected operations, but instead generated or purchased the same amount of energy or capacity. The owner of a qualifying facility is allowed up to one year to reimburse the utility for these costs.

16. Where no changes to the utility system are necessary except for installing additional metering, an average interconnection fee for qualifying facilities of 100 Kw or less shall apply.

17. The owner of a qualifying facility will indemnify and hold the utility harmless from all loss on account of injury, death or damage to property caused by the qualifying facility unless the injury, death or damage is the direct result of the negligence of the utility.

18. Qualifying facilities shall be required to execute a contract that specifies a one-year minimum term and describes the responsibilities, liabilities, ownership of equipment, and location.

19. The owner of a qualifying facility shall obtain and maintain general liability insurance in the amount of $500,000 for each occurrence or as determined by the Wyoming Public Service Commission.

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

State of Wyoming
Electric Rate Schedule

TABLE OF CONTENTS
CONDITIONS OF SERVICE Rate 100

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 91

TABLE OF CONTENTS
CONDITIONS OF SERVICE Rate 100

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 92

TABLE OF CONTENTS
CONDITIONS OF SERVICE Rate 100

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 93

TABLE OF CONTENTS
CONDITIONS OF SERVICE Rate 100

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 94

TABLE OF CONTENTS
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 generally 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 Regulatory Commissions as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. DEFINITIONS:

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

APPLICANT - A customer requesting Company to provide service.

COMMISSION AND COMMISSIONER - The Public Service Commission of Wyoming or a member thereof respectively.

COMPANY - Montana-Dakota Utilities Co.

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

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

DELIVERY POINT - The point where the Company's facilities join those of the customer.

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

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE - A customer desiring electric service must submit an application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. Any customer may be required to make a deposit as required by the Company in accordance with §V.4. The Company may refuse service or discontinue service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any customer who uses electric service 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 electric service until notified by the customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

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

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

4. RELOCATED FACILITIES – Where Company facilities are located on or adjacent to a customer's premises and where there is an encroachment(s) to electric facilities caused by the customer; said customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

5. NOTIFICATION OF UNSAFE CONDITIONS – The customer shall immediately notify the Company of any unsafe conditions associated with the Company's electric facilities at the customer's premises.

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

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

IV. LIABILITY:

1. CONTINUITY OF SERVICE – The Company's electric system is unusually widespread and has many interconnections with sources of power other than its own generating stations and it is subject to exposure by storms and other factors not under its control. The Company employs the latest developments in equipment and methods of operation for the purpose of maintaining adequate service. The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and

uninterrupted supply of electric service and will not be liable for any loss, injury, death or damage resulting from or caused by the interruption of the same.

2. CUSTOMER'S EQUIPMENT - Neither by inspection or rejection, nor in any other way does the Company give any warranty, expressed or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer, leased by the customer from third parties or used on the customer's premises. It is the obligation of the customer to consult with the Company regarding available maximum fault current and to provide such protection devices as may be necessary to safeguard the equipment and installation from interruptions, variation in voltage and frequency, single-phase energization of three-phase lines, reversal of phase rotation or other abnormal conditions. (Refer to Paragraph 710)

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 electricity or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

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

5. FORCE MAJEURE - In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of

any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or Company, acts of public enemies 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 electric lines, animal interference, sudden partial or sudden entire failure of electric transmission or supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required

for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

V. GENERAL TERMS AND CONDITIONS:

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

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

3. ELECTRIC SERVICE AVAILABILITY - Residential Electric Service is available to any residential customer for domestic purposes only. All normal sized equipment used for domestic lighting, heating, cooking and power, and used strictly for household purposes, may be supplied through one meter.

   a. Residential service is defined as service for domestic general household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments and mobile homes (this is not an all-inclusive list). In addition, auxiliary buildings on the same premises as the living quarters, used for residential purposes, may be served on the residential rate.

   Motors and other equipment which interfere with service to neighboring customers, all motors larger than 5 horsepower and

temporary or seasonal loads totaling more than 25 kilowatts (Kw) will not be permitted on the Residential Electric Service Rate without prior Company approval.

Only single phase service is available under the Residential Electric Service Rate.

b. Three phase service shall be served under the appropriate General Electric Service Rate.

c. General Electric Service is defined as service provided to nonresidential services, such as 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 parlors, 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).

d. If separate metering is not practical for premises that is using electricity for both residential purposes and for conducting business (or for nonresidential purposes), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or General) applicable to the type of service which constitutes more than 50% of the total connected load.

e. These rules will not change the classification of existing customers who were served electricity prior to October 1, 1988 except in the event of a different customer taking responsibility for the account.

f. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations

pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the appropriate General Electric Service Rate.

4. CUSTOMER DEPOSITS - The Company may require a deposit from an applicant for electric service (applicant) or an existing customer in accordance with Chapter 3, Section 7 of the Wyoming Public Service Commission's Rules:

The Company may require a deposit to guarantee payment for each service. This deposit shall not be considered as an advance payment of bills but shall be held as security for payment of service rendered. The Company may refuse service to an applicant or discontinue service to a customer for failure to comply with customer deposit requirements. The Company shall apply the policies governing customer deposits uniformly.

a. The Company may require a deposit if:

i. A prior service account with the Company remains unpaid and undisputed at the time of application for service;

ii. Service from the Company has been discontinued for:
A. Nonpayment of any undisputed delinquent bill;

B. Failure to reimburse the Company for damages due to the customer's negligent or intentional acts; or

C. Acquisition, diversion or use of service without the authorization of or knowledge by the Company;

iii. Information provided upon application for service is materially false or a misrepresentation;

iv. The application is for initial service with the Company or the applicant did not have service with the Company for a

period of at least 12 consecutive months during the past four years;

v. The applicant or non-residential customer is unable to pass an objective credit screen. In order to pass the objective credit screen, the applicant or non-residential customer must fulfill one or a combination of the following:

A. Received 12 consecutive months of service from the Company, with the undisputed portions of the 12 most recent bills paid in full when due;

B. Have a favorable credit rating with a third-party credit reporting agency; or

C. Receive a favorable credit rating from the Company's financial risk assessment tool.

vi. The request is for service at an address where a former customer with an undisputed delinquent bill for service still resides or conducts business;

vii. The applicant or the customer, has been brought within the jurisdiction of the bankruptcy court, or has had a receiver appointed in a state court proceeding, within the five-year period immediately preceding the request for service; or

viii. The Company has determined that it has a significant financial risk in continuing to provide service to a specific non-residential customer. The Company and the customer may attempt to reach a deposit agreement. If the Company and the customer are unable to reach an agreement, the Company shall file a confidential petition requesting expedited review and Commission approval prior to collecting the customer deposit. The petition shall contain the basis for the Company's determination, the amount of

deposit sought and sufficient information for the Commission to contact the customer.

b. The Company shall not require a deposit as a condition of new or continued utility service based upon any criterion not specifically authorized by the Wyoming Public Service Commission's Rules.

c. Unless otherwise ordered by the Commission, the required deposit shall not exceed the total amount of the customer's estimated bill for three months of highest use based on the premises' monthly bills during the immediate previous 12-month period. If billing information for the immediate previous 12-month period is not available, the deposit will be based on anticipated service characteristics and anticipated load.

d. The Company shall retain records showing:

   i. The name and address of each customer making the deposit;

   ii. The date and amount of the deposit; and

   iii. Each accounting transaction concerning the deposit.

e. The Company shall provide the customer a non-assignable receipt or other record of deposit, showing the date and amount received.

f. The Company shall calculate simple interest on deposits at the Commission Authorized Interest Rate described in Chapter 1, Section 2 (a)(xv) of the Wyoming Public Service Commission's Rules. Interest shall apply only to deposits held for at least six months, but shall accrue from the initial date of deposit through the date the deposit is returned to the customer.

g. The Company may accept a written guarantee from an acceptable guarantor in lieu of a deposit to pay a customer's bill. After the Company has verified the customer's identity, the customer shall agree to permit the Company to provide the customer's account information to the guarantor upon the customer's default.

h. Deposits and any unpaid interest earned on deposits shall be applied as a credit to the customer's bill, unless requested by the customer to be refunded, when:

i. The accrued interest equals or exceeds $10.00. The Company shall apply the credit at least annually;

ii. A residential customer has received 12 consecutive months of service, with no cause to discontinue service; and the customer's bills have been paid when due;

iii. A commercial or industrial customer has received 12 consecutive months of service, with no cause to discontinued service; the customer's bills have been paid when due; and the customer passes the Company's objective credit screen; or

iv. Service is discontinued. The Company shall not require the customer to provide the original receipt in order for the deposit to be returned. Any credit balance on the account after the deposit is applied shall be refunded to the customer. If the Company is unable to make the refund due to lack of knowledge of the customer's location, additional interest will not accrue after the service discontinuation date. The Company shall manage such deposits as unclaimed property as required by Wyoming law (W.S. § 34-24-109).

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

5. METERING AND MEASUREMENT

a. Company will meter the electric service 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.

b. Meter Testing

1) Company's Testing - The Company's ongoing meter testing program is set forth in Rate 115.

2) Customer's Request - Upon request of the customer for a test of the accuracy of the Company's meter used on the customer's premises, the following provisions shall apply:

a. If the meter has not been tested within 12 months, the Company shall perform the test within a reasonable time without charge to the customer. The Company shall notify the customer of the time when the Company will conduct the test so the customer or the customer's representative may be present.

b. If the meter has been tested within 12 months, the Company shall notify the customer the cost to perform the test. The Company shall notify the customer of the time when the Company will conduct the test so the customer or the customer's representative may be present.

c. The Company shall promptly advise the customer of the test results.

d. If a meter is found to be in non-compliance with the Company's approved meter testing program, the

Company shall refund the payment the customer advanced for the meter test and shall repair or replace the meter. The Company shall also adjust and refund to the customer the overpayment of preceding bills, in accordance with §V.6. No refund is required from the Company except to the customer last served by the meter prior to testing. If the Company has under collected, the customer shall pay the adjusted costs in accordance with §V.6.

e. The meter accuracy test charge amount is provided in §VI.1.e.

6. BILLING ADJUSTMENTS

a. In accordance with Wyo. Stat. § 37-2-218, if the Company charged, collected or received any rate or rates in excess of the rates fixed in the Company's tariff, the Company shall immediately refund to the customer the difference between the rates fixed in the tariff and the rates charged, collected or received. This shall also apply to meter errors described in §V. 5.

b. If the Company undercharged a customer as a result of a meter or metering inaccuracy or other continuing problem under the Company's control, the Company may bill the customer in accordance with Wyo. Stat. § 37-2-222, for the amount of unmetered electricity rendered in the 183 days immediately prior to the date the Company remedies the meter inaccuracy. The typical time period over which the undercharge may be collected shall be 12 consecutive months. The customer may elect to pay over a shorter period, or the Company may allow repayment over a longer period. This shall also apply to meter errors described in §V.5.

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

7. LATE PAYMENT - Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to the percentage set forth in §VI.2. will be applied to any past due balance, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

8. RETURNED CHECK CHARGE - A charge as set forth in §VI.1.b will be collected by the Company for any check not honored by the customer's bank for any reason.

9. TAX CLAUSE
   a. In addition to the charges provided for in the electric 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:

      1. Any sales, use or excise taxes whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

      2. Any payment under any electric franchise ordinance amounting to more than 1% annually of the gross electric revenue derived by the Company from electric business within the corporate limits of the municipality, political subdivision, or other entity, imposing the payment.

      3. The taxes imposed by the Sheridan Ordinance as adjusted for accounting and billing costs.

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

10. UTILITY CUSTOMER SERVICES:

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

1. Fire Call

2. Investigate hazardous condition on customer premises.

3. No lights or power investigation.

4. Maintenance or repair of the following Company-owned equipment on the customer's premises:
   i. Meter
   ii. Overhead Service Line
   iii. Underground Service Line

b. The following service calls will be performed at no charge during the Company's normal business hours of 8:00 a.m. – 5:00 p.m. Monday through Friday local time:

1. A reconnection of service to an existing facility (cut-ins) or a discontinuation of service

2. Checking Voltage or Loads

3. Locating Radio, CB or Television Interference

4. High Bill Complaint

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

11. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS - For service requested by customers after the Company's normal business hours defined in §V.10 and on Saturday, Sunday, or legal holidays, a charge will be made for labor at the overtime service rate set forth in §VI.1.f. plus the cost of any required materials.

    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.

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

13. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS - A fee, as set forth in §VI.1.d. will be collected for reconnecting electric service to any customer who has discontinued electric service at the same location during the preceding 12 month period, provided no other customer has taken service at the same location in the meantime.

14. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS - All amounts billed for service are due by the due date on the bill and will be considered delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company in accordance with Chapter 3, Section 9 of the Wyoming Public Service Commission's Rules.

a. Discontinuation Notice - The Company may discontinue service by reason of nonpayment after issuing a disconnect notice and upon not less than 7 days' notice of proposed termination for residential customers and not less than 3 days' notice for nonresidential customers. The disconnect notice will be mailed or delivered to the account holder or by telephone after customer verification and mailed to any third party previously designated by the account holder. Additional notice may be provided electronically. The notice shall contain:

1. The name of the person whose account is delinquent and the service address to be discontinued;

2. The amount of the delinquent bill;

3. The effective date of the notice and the date on or after which service is to be discontinued;

4. The Company's specific address and telephone number for information regarding how to avoid service discontinuation;

5. The names of agencies or organizations that have notified the Company that they render assistance to eligible persons who are unable to pay their utility bills; and

6. A statement advising the customer how to contact the Commission if discontinuation is disputed.

b. Landlord Account Holders - When the Company is discontinuing service for nonpayment by a landlord, the Company shall post, mail, or deliver to each known tenant a written notice, excluding the dollar amount, informing the tenant only of the impending disconnection and advising each tenant it has 15 days to arrange directly for service, as permitted by the available facilities. The tenant shall not be held responsible for the landlord's delinquent utility billings. The Company will post the

notice at a central location on or in the rental building if all tenants cannot be identified.

c. The Company will notify the customer that, if prior to the initial date for the discontinuation of service, the customer provides the Company with written verification from a health care provider responsible for the care of customer or his/her co-habitants stating that their health or safety would be seriously endangered if service were discontinued, the Company shall extend the date for discontinuation set forth in the notice by 15 days (22 days total) to allow for bill payment.

d. The Company shall attempt to make actual contact with the customer either in person or by telephone, after the customer verification, before discontinuing service during the cold weather period of November 1 through April 30.

e. The Company shall also provide notice of discontinuation or account delinquency to a third party if the customer or person acting for the customer has requested that the Company do so after the customer identification verification. The Company shall advise the Customer that the right to request third-party notification does not create third-party liability for payment.

f. If the customer defaults, the Company shall provide the discontinuation notice to any guarantor and the customer simultaneously. The guarantor's service shall not be subject to discontinuation as a result of the customer's default.

g. The Company shall remove a guarantor when:

1. The customer has received 12 consecutive months of service with no cause for discontinuation, bills have been paid when due and the customer passes an objective credit screen;

2. The guarantor has paid all amounts due for service through the date the Company received the request to terminate the guarantor agreement; or

3. An additional agreement with the Company is in place.

h. Reconnection After Nonpayment - To have service restored after discontinuation of service for nonpayment, a residential or a non-residential customer must first pay a charge for reconnection as set forth in §VI.1.c, and must also pay the delinquent balance in full or execute a written deferred payment agreement, if eligible. The Company may also require a deposit to secure payment of future electric bills. See §V.4 Customer Deposits.

i. Discontinuation - The Company may discontinue service between 8:00 a.m. to 4:00 p.m., Monday through Thursday if not a legal holiday or the day preceding a legal holiday without further notice when:

1. The notification period has elapsed and the delinquent account has not been paid; or

2. Acceptable payment arrangements have not been made with the Company.

j. Service Extender – Service Extender provides a temporary alternative to discontinuing electric service for non-payment by extending a controlled level of service to the delinquent customer prior to service being discontinued. The minimum size Service Extender used for a Residential customer is 10 amps. Service Extenders shall not be applicable to a residence where the primary source of heating is electricity. If the Company choses to install a Service Extender, service may be

discontinued without further notification. Notification of the Service Extender shall be delivered to an adult or posted at the affected premises and shall include:

1. The customer's name;

2. Date the Service Extender was installed;

3. Customer operational instructions for the Service Extender;

4. Telephone number and address of the Company; and

5. Warning that service may be discontinued without further notification.

k. The Company shall assist persons who are unable to pay their electric service bills with determining available government assistance.

15. PROHIBITIONS AGAINST SERVICE DISCONTINUATION – The Company shall not terminate service for bill nonpayment under the following conditions:

a. On a legal holiday as defined by Wyoming Statute §8-4-101, or the day before such a legal holiday;

b. During the period from December 24 through January 2, inclusive;

c. On any day in which the Company cannot reconnect service;

d. If the customer enters into an arrangement with the Company for payment of the delinquent billing over a reasonable time and the customer complies with payment arrangements;

e. If there are monies owed due to meter or other billing error, and the customer complies with payment arrangements;

f. At a previous address for a different class of service;

g. For nonutility services or appliance or merchandise provided by, or sold by, the Company to the customer;

h. If the customer is paying the electric service bills on time, even though a prior customer with an undisputed delinquent bill for service resides or conducts business at the same address;

i. If an electric service bill, or part of a bill, is legitimately in dispute, and if the customer duly pays the electric service bill, or bill portion, not in dispute;

j. If the temperature for the community closest to the customer's location is forecasted by the National Weather Service or other reputable source to be below 32°F in the impending 48 hours, or if conditions are otherwise especially dangerous to health, and the customer is:

   1. Unable to pay for service in accordance with the Company's billing requirements and is actively seeking government assistance or has exhausted such assistance; or

   2. Able to pay for service in installments; or

k. If the customer pays a bill on time for a specific service at a specific location, even though the customer is receiving another service that is subject to discontinuation for bill nonpayment.

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

16. 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. For the use of electricity for any property or purpose other than that described in the application made for service.

b. For failure to maintain in good order service entrance facilities or equipment owned by the customer.

c. For use of equipment which adversely affects the Company's service to its other customers.

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

e. The Company may discontinue service for causes other than non-payment after issuing a disconnect notice in accordance with §V.14 a. The discontinuance of service for causes other than non-payment shall occur on the days and during the hours stated in §V.14 i.

f. 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.

g. The Company may discontinue service without advance notice for reasons of safety, health, cooperation with civil authorities, fraudulent use, tampering with or destroying Company facilities.

h. The Company may collect a reconnect fee as prescribed in §VI.1.c. before restoring electric service which has been discontinued for the above causes.

17. 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 Montana-Dakota Utilities Co. The bill shall be computed at the applicable rate, and the amount reduced by 33 1/3%.

18. REFUSAL TO SERVE NEW CUSTOMERS OR EXPAND EXISTING SERVICE – A utility may refuse to provide, expand or materially change service to a requesting customer when:

    a. The Company does not have adequate facilities to render the service requested;

    b. The requested service appears to be unsafe or likely to adversely affect service to another customer; or

    c. The requesting customer is indebted to the Company for service previously rendered and satisfactory payment arrangements have not been made with the utility.

        1. If indebtedness for service rendered at a former location is in dispute, the requesting customer shall be provided service at the new location upon complying with the Company's deposit requirements and paying the amount in dispute. Upon settlement of the disputed amount, any balance due the customer shall be refunded with accrued interest at the Commission Authorized Interest Rate described in Chapter 1, Section 2(a)(XV) of the Wyoming Public Service Commission Rules.

        2. The Company shall not refuse service to a new customer because of debts of a previous customer at the same location.

        3. The Company may refuse service due to unpaid line extension charges for facilities serving the location.

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

VI. MISCELLANEOUS CHARGES

		Amount or Reference
1.	Service Charges	
a.	Consumer deposits	Rate 100 §V.4.
b.	Returned check	$20.00
c.	Minimum reconnect charge after discontinuation of service for nonpayment or other causes	
	- During normal business hours	$20.00
	- Removal of service extender	$20.00
	- After normal business hours	Minimum of $140.00
d.	Minimum reconnect charge applicable to seasonal or temporary customers	
	- During normal business hours	
	- Customers with non-demand meters	$20.00
	- Customers with demand meters	$40.00
	- After normal business hours	Minimum of $140.00
e.	Special test of meter at customer's request (see Rate 100 §V.5.b.2 as to when this charge is applicable)	
	- Meter error more than ±2%	None
	- Meter error within ±2% and meter was tested within the prior 12 months	Labor & materials Minimum of $25.00
f.	Service request after normal business hours	Materials & labor Minimum of $140.00

g. Electric extension policy — Rate 104

		Per Month	Approx. Annual Percent
2.	Late Payment Charges (on unpaid balance)	1%	12%

SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
Rate 104 - Electric Extension Policy
Rate 105 - Dark Sky Lighting Service
Rate 122 - AutoPay Plan
Rate 125 - Balanced Billing Plan

VII. ELECTRIC SERVICE RULES:

Section 100 – GENERAL

101. Electrical Codes and Ordinances

The Electric Service Rules and Regulations contained herein are supplementary to and do not intentionally conflict with nor supersede the latest edition of the National Electrical Code, the National Electrical Safety Code, nor such state and municipal laws and ordinances that may be in effect in the areas in which the Company furnishes electric service, except that where the requirements of these Electric Service Rules and Regulations exceed those of such codes, laws, and ordinances, these Electric Service Rules and Regulations shall apply. Existing installations, including maintenance replacements, that currently comply with prior revisions of these rules and regulations, need not be modified to comply with these rules except as may be required for safety reasons.

102. Wiring Adequacy

Wiring codes provide minimum requirements for safety. Installation of wiring capacity greater than minimum code requirements is recommended to bring to the customer all the benefits of electric service and to protect building investment by minimizing obsolescence resulting from an inadequate wiring system.

103. Inspection of Wiring
Where permits and inspections covering customer's wiring and installation are required by local ordinance, it is mandatory that such requirements be fulfilled before the Company will make connections to the customer's installation. In locations where such inspections are not required by law or ordinance, an affidavit by the wiring contractor stating that the wiring has been done in compliance with the National Electrical Code will be acceptable.

104. Permits, Certificates, Affidavits
It is the responsibility of the customer to obtain all necessary permits, certificates of inspection or affidavits as required in Paragraph 103 above and to notify the Company promptly of any proposed alterations or additions to customer's load. Failure to comply with these requirements may result in delayed connection, interruption of service or damage to apparatus.

105. Consultation with the Company
105.1 The location, size and character of the customer's load and the current, voltage, frequency, phases, etc. which the Company has available at the customer's location will determine the type of service supplied to the customer.

105.2 Architects, engineers, contractors, electric dealers, wiremen and others must confer with local representatives of the Company to determine the type of service that will be available before designing or preparing specifications for new electrical installations or alterations to existing installations.

105.3 In all cases involving large installations and other cases where any doubt exists, full information as to the type of service available should be obtained from the Company.

106. Unauthorized Use of Service
106.1 Unauthorized use of service is defined as any deliberate interference that results in a loss of revenue to the Company. Violators are subject to prosecution.

106.2 Types of unauthorized use of service include, but are not limited to, the following:

(a) Bypass around meter.
(b) Meter reversed.

(c) Equipment connected ahead of meter.
(d) Tampering with meter that affects the accurate registration of electric usage.
(e) Electricity being used after service has been discontinued by the Company.

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

(a) All costs associated with investigation or surveillance;
(b) Estimated charge for non-metered electricity;
(c) All time to correct situation;
(d) Any damage to Company property.

106.4 A customer's service disconnected for unauthorized use of service shall be reconnected after the customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid any 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 equipment, costs incurred in the preparation of the bill, plus costs as outlined in Paragraph 106.3;
(d) Applicable reconnection fee;
(e) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with §V.4 and Chapter 3, Section 7 of the Wyoming Public Service Commission's Rules.

107. Unauthorized Attachments to Poles

107.1 The unauthorized attachment of any flags, banners, signs, clothes lines, antennas, etc. to Company poles is prohibited. The use of poles for placards or other advertising matter is forbidden. The Company will remove such unauthorized attachments without notice and may prosecute any such trespassers.

107.2 Customers are cautioned to locate antennas so that they are beyond falling distance from the Company's lines, either transmission or distribution. Antennas and lead-ins shall be located a safe distance from and shall never cross over or under the Company's lines or contact the Company's poles. The Company disclaims all responsibility where such equipment contacts the Company's lines, poles or equipment.

Section 200 - USE OF ELECTRIC SERVICE

201. Rate Schedules
Electric service will be billed under the rate schedule that applies to the class of service used. Rate schedules applicable to various classes of service may be obtained from the Company upon request.

202. Resale of Energy
The Company will not supply energy for resale except as expressly covered by special contract or where such provision is a part of the rate schedule.

203. Temporary Service
Temporary service is any service for construction work, carnivals, gravel pits, occasional lighting, etc., which is not expected to continue in use for a period long enough to justify the construction cost necessary for extending service. When temporary service is desired the customer shall, in addition to paying the scheduled rates, make deposit in advance in the amount of the Company's estimated cost of installing and furnishing such temporary service facilities together with the cost of disconnecting and removing same and the estimated billing to the customer for electric service. Final billing will reflect credit for the salvage value of materials used in providing the temporary service. Any deficiency in such advance payment shall be paid by the customer upon presentation of a bill by the Company. Any amount deposited in excess of final billing by the Company will be refunded to the customer.

204. Standby Service
Where electric service is supplied as standby to a customer's generating facilities or vice versa, the customer shall provide and install at the customer’s expense a suitable double-throw switch or other device which will completely isolate the customer's power facilities from the Company's system. The service entrance shall be installed so that the

phase conductors will be totally isolated from the customer's wiring before the standby unit is put into operation.

205. Parallel Service

Parallel operation of the customer's generating equipment with the Company's system shall be permitted to the extent provided in other approved rates.

206. Transformer Installations on Customer's Premises

206.1 The Company will supply transformers to be installed on the customer's premises when requested by the customer and in accordance with the following paragraphs.

206.2 The customer shall agree to indemnify and save the Company harmless, except for willful default or neglect on the Company's part, from any loss, damage, expense or liability, incurred or arising from, or out of the installation, operation, maintenance, repair or removal of its transformers, cables, conductors, apparatus and all other Company property, material or equipment placed on the customer's premises.

206.3 Company's power or distribution transformers will not be installed in the customer's building.

206.4 The Company will furnish, own and maintain conventional oil filled transformers at no cost to the customer. However, where dry type transformers, transformers containing a nonflammable insulating coolant or oil filled transformers of special voltage or design are required they shall be owned, installed and maintained by the customer at the customer's expense.

206.5 Padmount transformers may be installed on customer's premises. The customer shall furnish a suitable concrete pad, conduit, ground rod and service conductors as noted in Figure 5. Where the customer has more than four parallel conductors, a cable junction enclosure and conduits to the transformer location may be required. The customer shall consult with the Company to determine when a cable junction enclosure is required.

206.6 Where the transformer is installed adjacent to an asphalt or concrete driveway, parking lot, or walkway, the customer shall provide conduit from the transformer location to a point beyond the driveway, parking lot, or walkway to accommodate the Company's

primary voltage cable. The customer shall provide barriers and clear zones to protect transformer from damage and to allow proper cooling and access to conductor compartments. The customer shall consult with the Company to determine the proper size conduit and protective barriers.

206.7 Refer to Figure 5 for additional information on transformer location.

Section 300 - ELECTRIC SERVICE AVAILABLE

301. Frequency

All service supplied by the Company is alternating current at a nominal frequency of 60 Hertz.

302. Secondary Voltages (See also Section 400.)

302.1 In general, the following classes of service are normally supplied:

Phase	Wires	Nominal Voltage	Nominal Service	
	1	3	120/240	Single Phase Lighting & Power
	3	4 Delta	120/240	Combined Light & Power*
	3	4 Wye	208 Grd Y/120	Combined Light & Power
	3	4 Wye	480 Grd Y/277	Combined Light & Power**
	3	4 Delta	240/480	Combined Light & Power*

*Overhead Primary
**Underground Primary

Note: The Company follows the provisions of ANSI C84.1; latest revision, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

302.2 Only one class of service voltage is provided to a single customer location.

302.3 Service at other voltages may be made available for approved loads upon special application to the Company. Supplying such service may require special construction and equipment by the customer and the Company. The details of such construction and equipment are subject to negotiation between the Company and the customer before service is supplied.

302.4 As the voltage and number of phases which will be supplied depend upon the character of the load, its size, and location, it is necessary that the customer consult with the Company regarding the type of service which will be furnished before proceeding with the purchase of equipment or the installation of wiring. (Refer to Paragraph 105)

302.5 The customer's wiring for single phase installations shall be such that the difference in loads on each side of the supply neutral shall not exceed 10% of the total load.

302.6 For three phase grounded wye installations, the load shall be balanced so that the difference in loads on the separate phases shall not exceed 10% of the total load.

303. Primary Voltages (See also Section 500.)
Service may be made available at primary voltage of 2400 volts or higher. The available primary voltage is dependent upon the local primary voltage.

Section 400 - SECONDARY VOLTAGE SERVICE
(Under 600 Volts)

401. Secondary Voltage Service Connections
The location of the service connection is subject to approval by the Company. The Company will cooperate with the customer to the fullest extent practicable in determining such location. Once established, any change by the customer may result in billing to the customer for any additional work or materials required by the Company.

402. Service Connections and Disconnections
All connections or disconnections of overhead or underground services, regardless of the voltage, will be made by the Company at the point where the Company's facilities join those of the customer. No customer or agent of the customer will be authorized to make such connections or disconnections. (Refer to § III.1. and Paragraphs 103 and 104)

403. Number of Service Drops
In general, one service drop will be installed for each customer location. Exceptions will be made in special cases where it is mutually advantageous to the customer and the Company.

404. Services in Raceways
Where services are installed in raceways, the installations must comply with the requirements of the latest edition of the National Electrical Code. In addition, effective with services installed on and after April 25, 2006 metered conductors shall not be installed in the same raceway as unmetered service conductors.

405. Service Entrance Requirements
405.1 The Company recommends that the service entrance for single family residences be not less than 100 ampere. The service entrance shall be sized and installed in accordance with provisions of the National Electrical Code, state code, and local ordinances. Bare neutral wire shall not be installed in metallic conduit due to the possibility of radio interference.

405.2 Ample length of service entrance conductor shall be left protruding from the service head and at padmount equipment facilities to allow for proper connection to the service drop for overhead installations and to padmount equipment terminals.

405.3 When entrances are parallel in two or more conduits, all phases shall be run in each conduit and all wires shall be of the same length.

406. Identification of Conductors
406.1 For purposes of identification, the neutral wire of each single phase entrance shall be clearly marked at the service outlet as well as at the meter location.

406.2 Where 4-wire, three phase service entrances are installed, the neutral conductor and the "wild" phase conductor (nominal 208 volts to ground) shall each be clearly marked at the service outlet, at the meter and at service equipment.

407. Overhead Service Drops
407.1 The service entrance shall preferably be through the eave and be located so the overhead service drop will be as short as practical and maintain all clearance requirements. (Refer to Figure 1 and Paragraph 407.4)

407.2 In cases where proper clearances cannot be maintained by attaching the service drop directly to the building, the customer shall install and maintain a supporting

structure of sufficient mechanical strength to support the wires and of sufficient height to provide the necessary clearances.

407.3 The customer shall furnish and install the necessary facilities for firmly mounting a Company supplied service drop attachment.

407.4 Service drop conductors shall not be readily accessible and when not in excess of 750 volts, shall conform to the following general requirements (Refer to the National Electrical Safety Code for possible exceptions) :

Clearance over roof – Multiplex service drop conductors shall have the following minimum clearance over a roof:

10.0 feet - from the highest point of roofs or balconies over which they pass with the following exceptions:

Exception 1: The clearance shall be maintained at not less than 3.0 feet above roof or balcony not readily accessible.

Exception 2: Where a roof or a balcony is not readily accessible, and a service drop passes over a roof to terminate as a (through-the-roof) raceway or approved support located not more than 4.0 feet, measured horizontally from the edge of the roof, the clearance above the roof shall be maintained at not less than 1.5 feet for a horizontal distance of 6.0 feet from the raceway or support, and shall be maintained at not less than 3.0 feet for the remainder of the horizontal distance that the cable or conductor passes over the roof.

Note: A roof or balcony is considered readily accessible to a person, on foot, who neither exerts extraordinary physical effort nor employs special tools or devices to gain entry.

Clearance from ground – Multiplex service drop conductors shall have the following minimum clearance from ground:

18.0 feet - over roads, streets and other areas subject to truck traffic. Trucks are defined as any vehicle exceeding 8 feet in height.

18.0 feet - over driveways, parking lots and alleys. This clearance may be reduced to the following values:
(1) 17 feet – where multiplex service drops cross over or run along alleys, driveways, or parking lots.
(2) If the height of attachment to a building or other installations does not permit these requirements:
(a) 14 feet – over residential driveways for multiplex service drops limited to 150 volts to ground.
(b) 10 feet – over residential driveways for drip loops of service drops limited to 150 volts to ground.

14.0 feet - over spaces or ways accessible to pedestrians or restricted traffic only. This clearance may be reduced to the following values:
(1) If the height of attachment to a building or other installations does not permit these requirements:
(a) 12 feet - for multiplex service drops limited to 150 volts to ground.
(b) 10 feet - for drip loops of service drops limited to 150 volts to ground.

24.5 feet - over swimming pools, or within 10 feet, measured horizontally, of the pool edge. In addition, there must be 16.5 feet clearance measured in any direction from every point on a diving platform or tower.

The vertical clearance is derived using the latest edition of the National Electrical Safety Code rule and, where necessary, adding 2 feet for vertical movement safety factor adopted by Company.

408. Secondary Voltage Underground Service

408.1 Where the customer desires an underground service, the customer must furnish and install conduit from the line side of the meter socket to a point a minimum of 18

inches below grade. (Refer to Figure 1.) The customer shall also provide necessary conduit for services under any asphalt or concrete drive-way, walkway, parking lot, or other areas where it is impractical to excavate.

408.2 If a customer requests to convert from an overhead service to an underground service, the customer must provide all necessary changes to the service entrance, including relocation, and the conduit described in 408.1 above. The customer must also provide a Company approved trench ready to accept the underground service conductors including back filling, surface restoration and any future settlement or erosion. If the customer requests the Company to provide this work, the Company will charge the customer for this service. In addition, if the service length is less than 150 feet, a fee equal to the Company's labor and equipment costs to convert the average 100 feet service line will be charged. If the service length is greater than 150 feet the customer will pay a fee equivalent to the Company's actual labor and equipment costs for the conversion.

409. Mobile Home Service

The customer shall install and maintain the metering pedestal or meter socket and meter mounting device. The customer, as the term is used in this section, is considered to be the mobile home court owner for installations in mobile home courts and the mobile home owner for installations on a private lot.

Section 500 - PRIMARY VOLTAGE SERVICE
(2400 Volts or More)

501. General

The Company offers electric service at primary voltages of 2400 volts or higher. A customer desiring to take service at primary voltage shall furnish and own all electrical equipment from the point of delivery and shall consult the Company to assist in determining the size, type and arrangement of service entrance equipment and conductor specifications required for the customer's particular needs.

502. Service Entrance Equipment

The service entrance equipment shall perform the following functions:

a. Isolate the load from the supply circuit by visible means.
b. Automatically break the circuit in the event of overload.
c. Permit manual opening of the circuit at full load.

503. Overcurrent Protection

The need for overcurrent protective coordination requires consultation with the Company. Overcurrent protective devices may be as follows:

a. Fuses
b. Automatic trip circuit breakers

The overcurrent protective device must have an interrupting rating, at circuit voltage, equal to or exceeding the maximum short circuit current available at the location where service is taken.

504. Disconnecting Means

504.1 The disconnect switch shall provide visible evidence that the circuit to which it is applied is open or disconnected. It shall be located on the supply side of the circuit.

504.2 Where fuses are used, the disconnect switch shall be a gang operated load break switch.

504.3 Where automatic circuit breakers are used as circuit protective equipment, the disconnect switch can be non-load break.

505. Load Balance

Loads on the three phases shall be balanced as closely as possible. The maximum unbalance permitted between individual phase loads is 10% of the total three phase load.

Section 600 - METERING

601. General

The Company will install the necessary meters to measure the electrical energy delivered under each account for a particular class of service. The Company shall install and maintain at its own expense all equipment necessary to regulate and measure the commodity delivered per tariff.

601.1 Meter Reading and Billing

a. Each service meter shall clearly indicate the units of measurement. If the utility bills customers in a different unit of measurement than the service

meter indicates, the conversion factor shall be stated on the customer bill. In cases where special types of meters are used or where the readings of a meter must be multiplied by a constant to obtain the units consumed, that information shall be placed on the customer bill.

b. Bills shall be rendered periodically and shall show the meter readings at the beginning and end of the billing period, the date of the meter readings, the units consumed, the class of service and other information necessary to enable the customer to readily re-compute the amount of the bill. Each bill shall bear upon its face the date of the bill and the latest date it may be paid without penalty. Estimated meter readings or budget billing shall be clearly identified on the bill. Electric meters shall be read monthly as nearly as possible on the same day within the billing cycle.

602. Meter Installations

602.1 The Company will furnish all meters required for billing purposes. It shall be the customer's responsibility to furnish, install and maintain the meter mounting device. Company approved specifications for electric meter sockets and metering transformer enclosures are listed below:

Self-Contained Meter Sockets - Single Phase, Three Phase and Multiple Position Type

1. The customer will utilize meter sockets from a Company approved list of manufacturer and models as posted on the company's website.
2. U.L. approved, ringless style.
3. 100 ampere minimum for overhead service installations. 200 ampere minimum for underground service installations.
4. Stud connectors are required for all socket rated 320 amps of greater.
5. For sockets rated below 230 amps, stud connectors are recommended. Only Company specified meter sockets are approved with lay-in connectors.
6. Equipped with a fifth terminal in the nine o'clock position where network metering is required.
7. A lever by-pass feature is required for all commercial and industrial installations. Upon review by Company, an exemption may be provided.

8. A lever by-pass feature is recommended for all residential installations.

Metering Transformer Rated Meter Socket

1. U.L. approved, ringless style with a one piece cover.
2. Minimum size must provide space for test switch installation.
3. Socket must have six terminals for single phase and 13 terminals for all other configurations.
4. Automatic by-pass feature is not acceptable.
5. The customer will utilize instrument rated meter sockets from a Company approved list of manufacturer and models.

Metering Transformer Enclosure (Secondary Service)

1. Recommend a durable, weather-resistant finish and weather-proof seal.
2. Must be provided with hinge-type cover and provisions to attach locking or sealing device.
3. Minimum size 10" x 24" x 30" with suitable mounting brackets for current and voltage transformers.
4. Consult with Company prior to purchasing any metering transformer enclosure.

602.2 Self-contained rate meter sockets shall be placed outdoors.

602.3 On instrument rated meter sockets, the Company will furnish and install the metering transformers. Such meter sockets shall be arranged for outdoor metering. (Refer to Figures 2 and 3)

602.4 Where a secondary metering transformer enclosure is required, the customer shall furnish and install an enclosure. Such enclosures shall contain only the service entrance conductors and metering transformers. The metering transformers shall be installed on the line side of the customer's disconnecting device. Suitable lugs, connectors, etc. for connecting metering transformers to service mains shall be provided by the customer. (Refer to Paragraph 602.1)

602.5 For installations having switchboards, the metering transformers may be mounted in the switchboard bus, provided they are accessible for changing and testing. Metering transformers shall be mounted on the source side of the main switch.

602.6 Meters and test switches may be mounted on a suitable unhinged panel adjacent to the metering transformer enclosure.

602.7 No device other than a Company-owned or Company-approved device shall be placed into the meter socket.

603. Meter-Switch-Fuse Wiring Sequence

For all secondary voltage metering installations, the meter entrance switch and main line fuse or breaker shall be installed in the order named with respect to power flow. All circuits downstream from the meter shall have proper overcurrent protection devices. A customer-owned main service switch shall be installed on the source side of all 480 volt, self-contained meters. This switch shall be located no closer than three feet either left or right of the meter socket, and the switch cover is sealed by the Company.

604. Meter Locations

604.1 Each meter shall be located outdoors in a place of convenient access where it will not create a hazard. The location shall be agreed upon by the customer's representative and the Company and in compliance with Chapter 3, Section 16 of the Wyoming Public Service Commission's Rules. (Refer to Figure 1)

604.2 Meters shall be located so that there is not less than 3 feet of unobstructed space, from the ground up, in front of the meter so that the center line of the meter is not less than 4 feet nor more than 5 feet above the floor, ground, or permanent platform from which the reading will be taken. On group installations, the minimum height is 2 feet – 6 inches and the maximum is 6 feet. The minimum center spacing between meter sockets shall be 7 ½ inches horizontally and 8 ½ inches vertically.

604.3 Meter Sockets shall be permanently mounted on secure structures such as houses, buildings, poles, etc. All required conduit will be provided by the customer. (Refer to Figures 1, 2 and 3)

604.4 Enclosures shall not be placed over the meter socket unless approved by the Company.

605. Indoor Metering
Meters shall be located outdoors as noted in Paragraph 604.1. However, depending on the circumstance and after consulting with the Company, locating the meters indoors may be approved on a case by case basis. Where approved, indoor meters for multiple dwellings, large office buildings, etc. shall be grouped and located as near the service entrance location as practicable. In the event such location renders the automatic meter reading equipment ineffective customer will be responsible for costs associated with remedying the situation.

606. Wiring Diagrams
Typical wiring diagrams for various types of self-contained meters are shown on Figure 4. These are subject to change from time to time with advancement in available metering equipment.

607. Labeling
Where two or more meter mounting devices are installed at one location, each shall be labeled so that it may be identified as to the customer served. Electrical contractors are requested and cautioned to check and identify wiring circuits carefully to avoid metering errors due to incorrect circuitry. Permanent (mechanically fastened) engraved plates shall be placed on the exterior of the meter base on a non-removable panel.

608. Seals
All meters and all points of access to customer wiring on the source side of the meter will be sealed by the Company. All cabinets and switch boxes, either inside or outside of the building, which contain unmetered wires shall have provisions made for sealing before service will be supplied.

Section 700 - UTILIZATION EQUIPMENT

701. Interfering Loads
Whenever a customer's utilization equipment has characteristics which cause undue interference with the Company's service to other customers, the customer shall provide, at the customer’s expense, the necessary equipment to prevent or eliminate such interference. The Company may install and maintain at the customer's expense and upon approval of the customer the necessary equipment to eliminate such interference if it deems it advisable. When a customer's equipment or method of operation causes

such interference and the customer does not correct the condition after being so requested by the Company, the Company reserves the right to discontinue the electric service, following written notification of its intent to do so; and service will not be re-established until the conditions complained of have been corrected.

702. Voltage Flicker and Harmonics

702.1 The Company uses the latest revision of the IEEE Standard 141 as the guideline for the maximum allowable voltage flicker that can be caused by a customer's load as measured at the point of metering. This guideline refers to the momentary dip in voltage that may result from the customer's operation of switches, starting of motors, etc.

702.2 Customer's electric load shall comply with the recommendations within Section 10 of the latest revision of the IEEE Standard 519 "Recommended Practices & Requirements for Harmonic Control in Electric Power Systems" at the point of metering connection. The IEEE Standard is available for review by the customer by contacting the Company to discuss by phone or to arrange an appointment at the Company's Sheridan office.

703. Power Factor

Whenever the customer's utilization equipment is of such characteristics as to produce a low power factor, the Company reserves the right to require the customer to raise such power factor, at the customer's expense, or to pay additional charges as provided in certain of the Company's rates on file with the Regulatory Commission of the state wherein the customer is located.

704. X-Ray Equipment

At the option of the Company, x-ray equipment may be separately metered and/or supplied from separate transformers.

705. Electric Welders

Electric welding apparatus shall require special arrangements with the Company to determine its ability to serve before installation is made. (Refer to Paragraph 703)

706. Electric Motors

706.1 Motors are normally designed to operate at their rated voltage, plus or minus 10%; thus a 220 volt motor should operate satisfactorily at 208 volts or 240 volts.

706.2 To assure adequate safety to personnel and equipment, the customer shall provide and maintain protective devices in each phase to protect all motors against overloading, short circuits, ground faults and low voltage, and to protect all three-phase motors against single-phasing and phase reversal.

706.3 Motors for use at 120 volts single-phase are limited to locked rotor currents of 25 amperes if started more than 4 times per hour, and 50 amperes if started less frequently.

Motors for use at 208 or 240 volts single-phase will generally be limited to 3 h.p. and a maximum of 4 starts per hour. The Company must be consulted for single-phase motors above 3 h.p. Compensating starting equipment may be required to limit the starting current and when required, shall be furnished by the customer. (Refer to Paragraph 702)

706.4 The size of the three-phase motors permitted will depend upon the effect starting the motor has upon the customer's system and the Company's other customers in the area. This effect will depend upon the magnitude of the starting current and the frequency of starting. (Refer to Paragraph 702)

When necessary, the customer will be required to reduce the amount of starting current to an acceptable level by installing suitable motor-starting equipment or by using motors designed for smaller starting currents.

706.5 When more than one motor can start simultaneously, the sum of the maximum starting currents of those motors starting simultaneously and also the sum of their horsepower rating shall be furnished to the Company to determine when reduced voltage starting may be required.

707. Flashing Display Signs

The Company reserves the right to refuse service for "flashing" display signs or display lighting where such service would interfere with voltage regulation of the secondary system.

708. Fluorescent and Gaseous Tube Lighting

High power factor ballasts or transformers must be used for fluorescent, sodium vapor, neon or other gaseous tube lighting equipment. It is required that such equipment operate at a power factor of not less than 90% lagging.

709. Electric Heat Equipment

A customer planning to install resistance type heating, heat pump, electric furnace, electrode boiler, etc. shall consult with the Company, before purchasing the equipment, so that operational modes of this equipment are determined to be acceptable for connection to the Company's distribution system. It is important that consultation is obtained prior to installation of this equipment so the Company can provide adequate capacity to efficiently serve the customer's requirements.

710. Computers and Electronic Equipment

Computers and other sensitive electronic equipment which require high grade, uninterrupted power may, on occasion, experience problems when connected directly to the Company's distribution system. The customer should contact their equipment supplier or consultant to ascertain the need for lightning arresters, surge suppressors, isolation transformers, and standby or uninterruptible power supplies. (Refer to § IV.2.)

711. Carrier Equipment

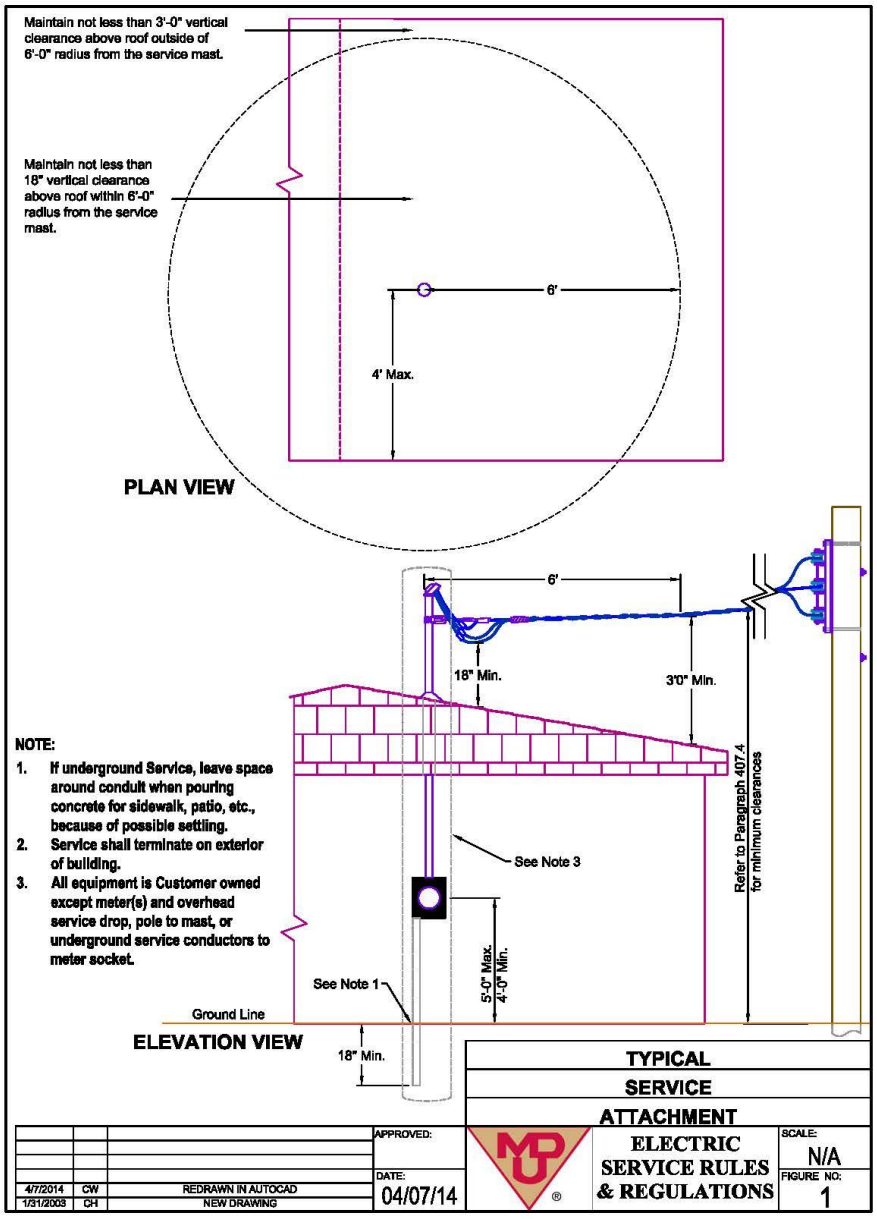
The customer shall not impose, or cause to be imposed, any electric signal of any frequency or magnitude upon the Company's distribution system that may produce ill effects on Company equipment, affect safety of personnel or affect other Customers' equipment.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 138

CONDITIONS OF SERVICE Rate 100



Date Filed: January 4, 2019

Issued By: Tamie A. Aberle
Director – Regulatory Affairs

Effective Date: Service rendered on and after January 1, 2019

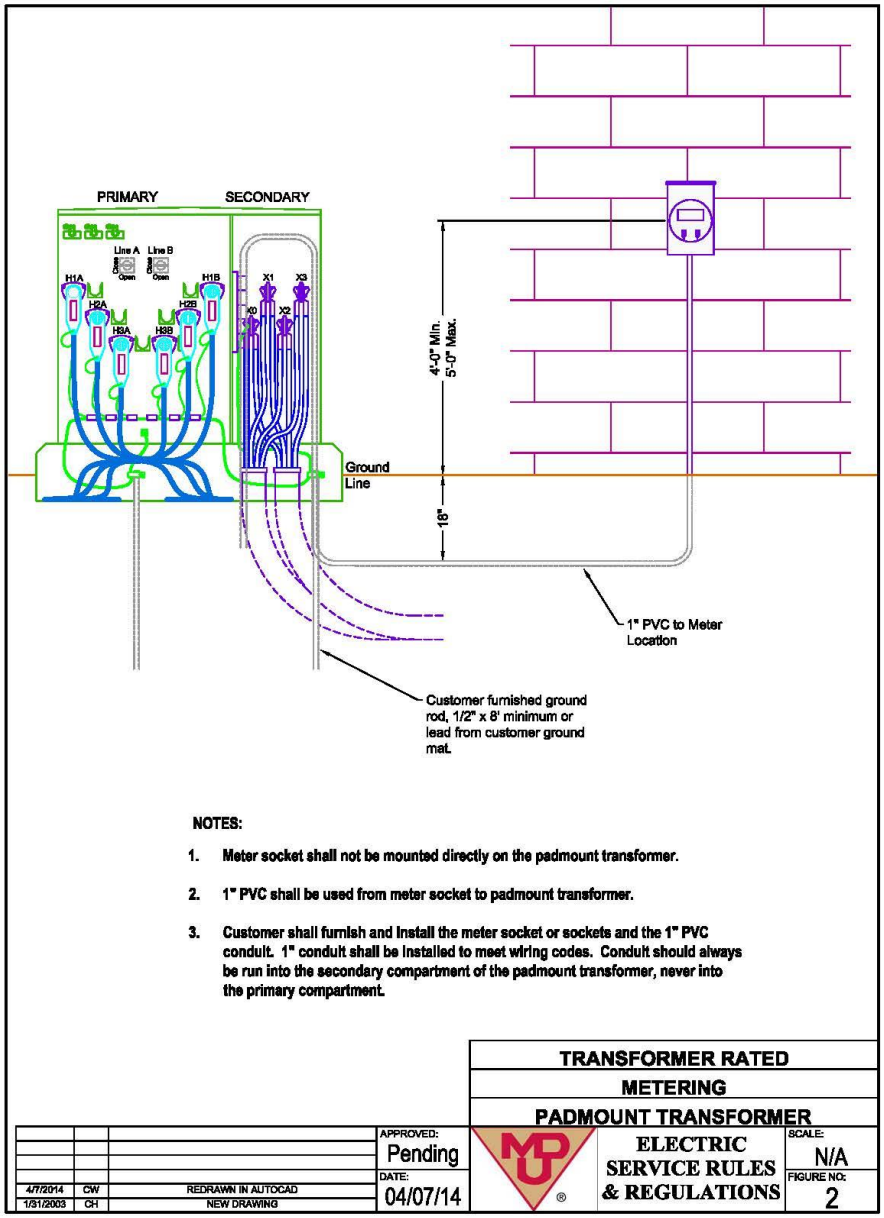
Docket No.: 20004-128-EA-18

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 139

CONDITIONS OF SERVICE Rate 100



NOTES:

1. **Meter socket shall not be mounted directly on the padmount transformer.**
2. **1" PVC shall be used from meter socket to padmount transformer.**
3. **Customer shall furnish and install the meter socket or sockets and the 1" PVC conduit. 1" conduit shall be installed to meet wiring codes. Conduit should always be run into the secondary compartment of the padmount transformer, never into the primary compartment.**

			APPROVED: Pending	TRANSFORMER RATED METERING PADMOUNT TRANSFORMER
			DATE: 04/07/14	ELECTRIC SERVICE RULES & REGULATIONS
4/7/2014	CW	REDRAWN IN AUTOCAD		SCALE: N/A
1/31/2003	CH	NEW DRAWING		FIGURE NO: 2

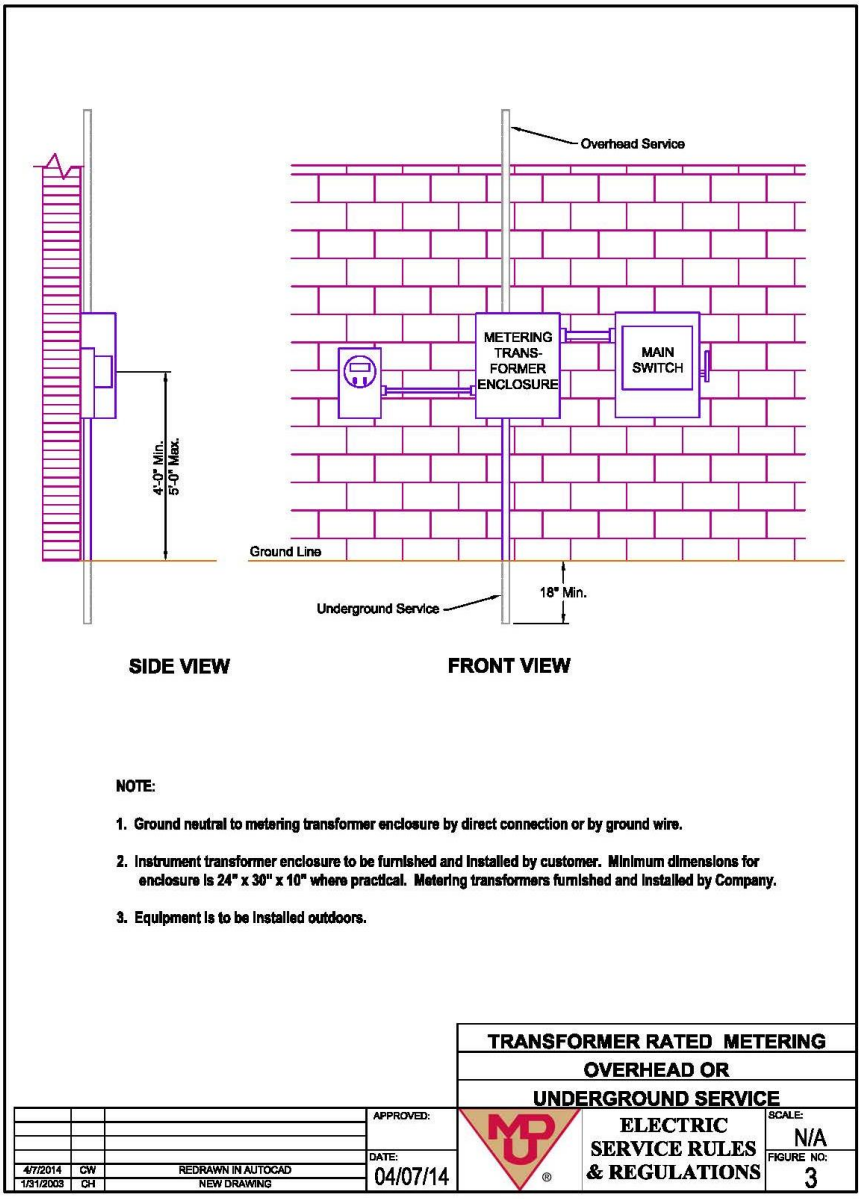
Date Filed:	January 4, 2019	**Effective Date:**	Service rendered on and after January 1, 2019
Issued By:	Tamie A. Aberle Director – Regulatory Affairs	**Docket No.:**	20004-128-EA-18

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 140

CONDITIONS OF SERVICE Rate 100



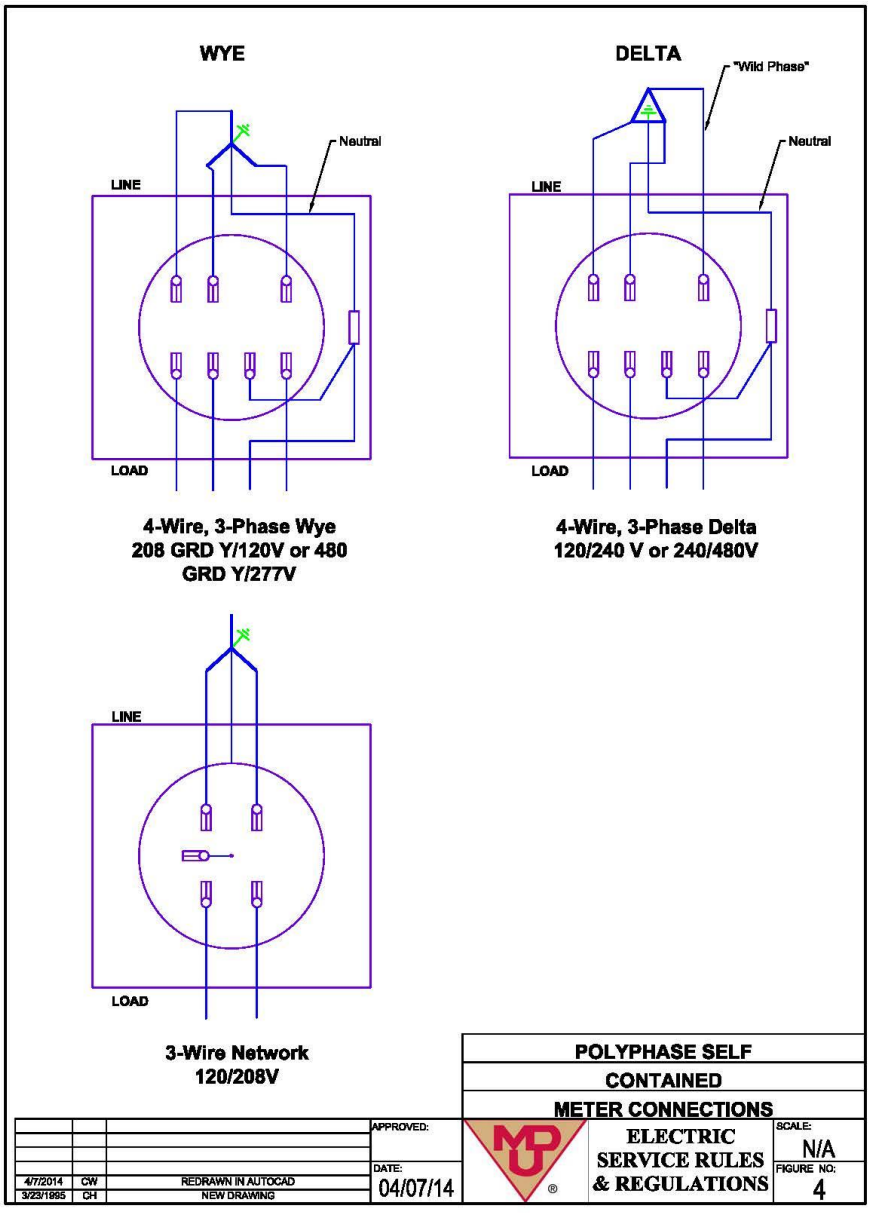
Date Filed:	January 4, 2019	**Effective Date:**	Service rendered on and after January 1, 2019
Issued By:	Tamie A. Aberle Director – Regulatory Affairs	**Docket No.:**	20004-128-EA-18

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 141

CONDITIONS OF SERVICE Rate 100



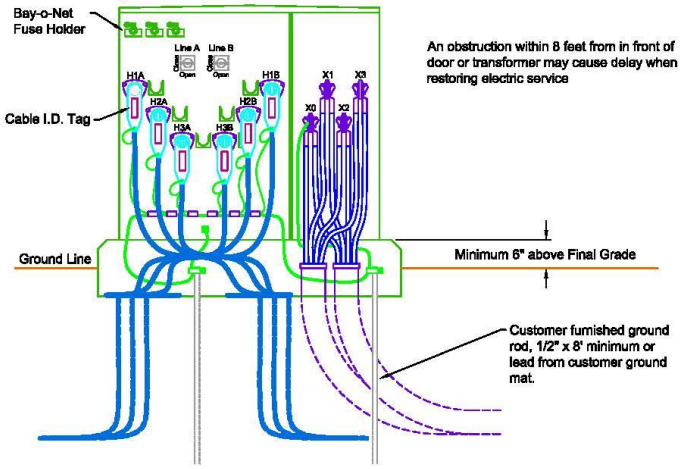
Date Filed:	January 4, 2019	**Effective Date:**	Service rendered on and after January 1, 2019
Issued By:	Tamie A. Aberle Director – Regulatory Affairs	**Docket No.:**	20004-128-EA-18

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 142

CONDITIONS OF SERVICE Rate 100



NOTES:

1. Consult with Company for actual equipment pad dimensions.
2. Transformer pad, service cable, conduit and ground rod or mat for service cable grounding are furnished by Customer.
3. Allow sufficient slack in service entrance conductor to allow for proper connection to equipment terminals.
4. Service connectors to be furnished by Company.
5. Connection to Company's equipment terminals to be made by Company.
6. When more than four condutors are installed for each phase, consult Company for transition cabinet requirements.

TRANSFORMER LOCATION

1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with ballards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.

			APPROVED: Pending	TYPICAL PADMOUNT EQUIPMENT INSTALLATION	SCALE: N/A
			DATE: 04/07/14	ELECTRIC SERVICE RULES & REGULATIONS	FIGURE NO: 5
4/7/2014	CW	REDRAWN IN AUTOCAD			
1/31/2003	CH	NEW DRAWING			

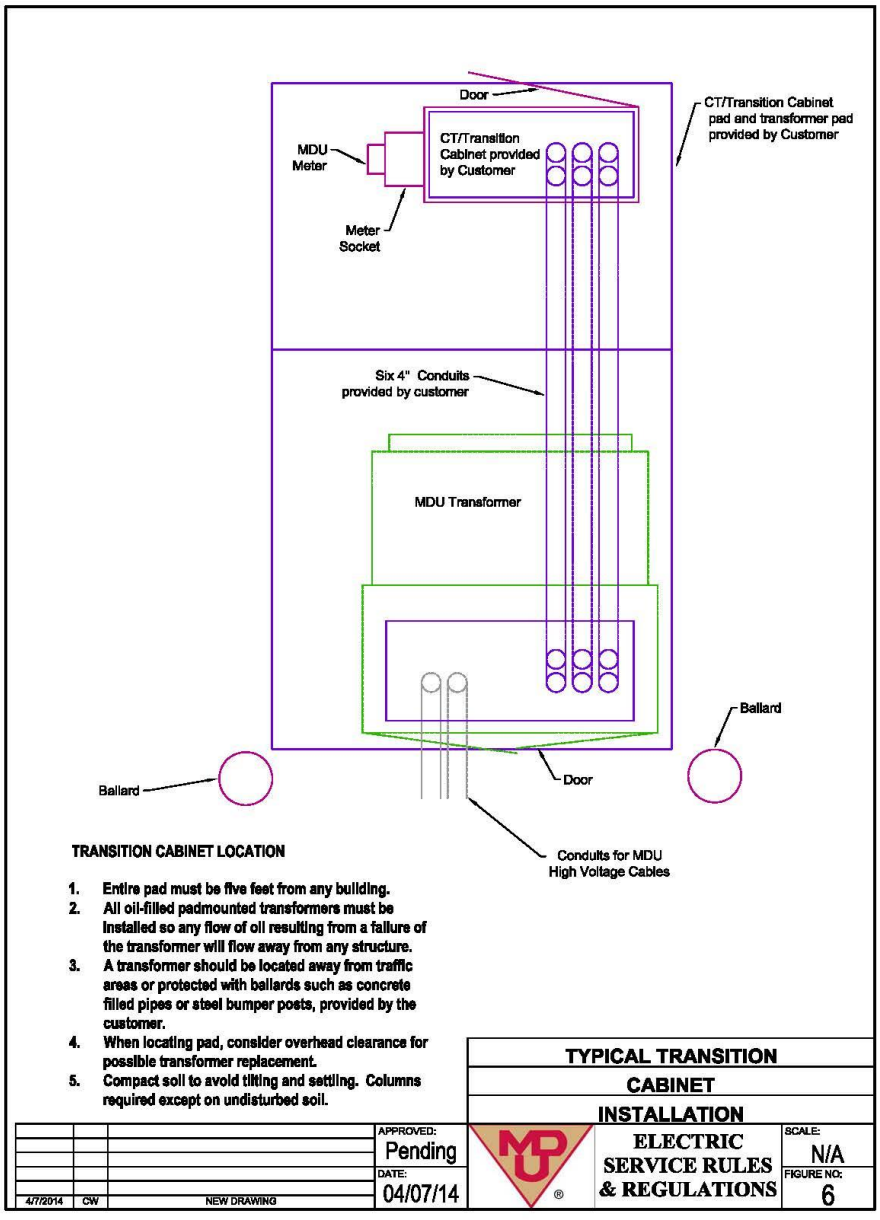
Date Filed: January 4, 2019
Effective Date: Service rendered on and after January 1, 2019
Issued By: Tamie A. Aberle, Director – Regulatory Affairs
Docket No.: 20004-128-EA-18

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 143

CONDITIONS OF SERVICE Rate 100



Date Filed: January 4, 2019

Effective Date: Service rendered on and after January 1, 2019

Issued By: Tamie A. Aberle
Director – Regulatory Affairs

Docket No.: 20004-128-EA-18

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 160

ELECTRIC EXTENSION POLICY
Rate 104

The policy of Montana-Dakota Utilities Co. for electric extensions is to provide service to any new customer.

1. A permanent extension may be constructed without a customer or developer contribution if the estimated project cost is equal to or less than 2.684 times the estimated annual revenue (2.684 to 1 ratio).

2. If the estimated project cost is greater than 2.684 times the estimated annual revenue, the extension will be made only with a customer contribution, which may be refundable.

    a. Contribution -

        1) When a contribution is required of any customer, with the exception of those customers defined in 2) below, the formula for determining the amount of the contribution required shall be as follows: Total project cost less 2.684 times annual revenue equals contribution amount.

        2) The contribution requirement for developers of subdivisions and industrial customers shall be the estimated project cost.

        3) The contribution shall be a one-time payment prior to construction.

        4) A minimum annual bill equal to the estimated annual revenue used in the contribution formula, will be applicable for a period of five (5) years. This amount will be as set forth on the Electric Service Agreement.

        5) Upon completion of construction, where actual costs are less than the estimated construction costs, a refund will be made for the difference, but not for an amount less than $25.00. No additional contribution will be requested from the customer where actual construction costs exceed the estimate unless unusual construction difficulties are encountered.

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

State of Wyoming
Electric Rate Schedule

ELECTRIC EXTENSION POLICY
Rate 104

b. Refund -

1) If within a five-year period from the date initial service is established, one or more additional customers are added to the above-referred-to extension, Company shall recompute the contribution required by combining the proposed project costs for the new customer(s) with the project costs of those customers already taking service. If, by so combining the project costs, the contribution of those customers already taking service would be less, Company shall make a proportionate refund, without interest, to those customers taking service prior to commencement of service to said additional customer(s).

2) If a customer makes a refundable contribution, the Company will refund to the customer annually, for a period of five years from the date service becomes available to the customer, an amount equal to fifty percent of the customer's bill, after first deducting the annual minimum, which minimum shall be equal to the estimated annual revenue used in the contribution formula, provided, however, that no refunds shall be made in excess of the amount contributed. The annual refund shall be paid only after the electric service bills for that year have been paid in full.

3) Refunds for developers of subdivisions shall be made for each lot connected based on the following calculation: Total refundable contribution divided by the number of lots that can be served from the extension equals refund per lot. In addition, the total revenue of the subdivision will be reviewed annually to determine if adequate revenues are being generated so that the contribution formula would indicate a zero contribution. When this revenue level is reached, a refund will be made to the developer equal to the remaining contribution amount still held by the Company.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 162

ELECTRIC EXTENSION POLICY
Rate 104

4) No refund shall be made by Company to customer(s) or developer after the aforementioned five-year period has expired.

5) No interest will be paid by Company to customer(s) on any amount customer(s) has paid to Company as a contribution in aid of construction for the project.

3. Project cost shall exclude the service line(s), transformer(s), and meter. The service line is considered to be the low voltage conductors between the Company owned transformer or secondary system and the customer owned service entrance equipment.

4. Company will deliver electricity to customer at the same rate approved by the Wyoming Public Service Commission.

5. Where a contribution in aid of construction is required to provide service, such extension is subject to prior execution by customer and Company of Company's standard agreement for extensions.

6. Where abnormal conditions exist, causing extraordinary costs on any part of the extension (e.g., railroad or river crossing, land clearing, special permits, etc.), a charge may be made equal to the additional cost incurred by reason of the abnormal conditions.

7. Temporary loads, such as gravel pit operations, carnivals, etc., shall follow the Company rules for temporary services.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 165

DARK SKY LIGHTING SERVICE
Rate 105

AVAILABILITY:

Optional customer owned lighting apparatus defined as any shield, cover or other device that is designed to minimize light illuminating unintended areas and maintain dark skies in accordance with Wyoming Statute Annotated §37-16-201 to 202. Such lighting fixture shall be used with or on a lamp served by Company under an otherwise applicable electric service rate schedule.

RATE:

Customer requesting such lighting apparatus shall be required to pay in full the actual cost of the materials and installation prior to installation of lighting apparatus.

GENERAL TERMS AND CONDITIONS:

1. Costs for the lighting apparatus shall be not subsidized by revenue from other Company provided services.

2. The Customer shall request in writing the lighting apparatus to be installed, the location of the installation and the illumination control desired.

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 167

SERVICE INTERRUPTION REPORTING PLAN Rate 106

The following sets forth the Company's Service Interruption Reporting Plan as required in Chapter 3, Section 27-28 of the Wyoming Public Service Commission's (Commission) Rules applicable to service provided by the Company in its Wyoming service territories.

A. Definitions of Service Interruptions:

1. Major Service Interruption shall be defined as:

   a. An event that results in estimated property damage of at least $50,000;

   b. An event that results in death, in-patient hospitalization, damage to the Company's property which substantially affects service to the public or is otherwise significant in the judgement of the Company;

   c. A sustained single feeder outage of two hours or longer to the lesser of 500 customers or 50 percent of the customers served;

   d. The loss of service to a distribution substation feeder or;

   e. Any service interruption which affects twenty five (25) or more customers for eight (8) hours or longer.

   Minor Service Interruption shall be defined as any sustained service interruption which affects at least one customer and is not defined as a Reportable Incident.

2. Scheduled Service Interruption shall be defined as:

   a. Any service interruption scheduled by the Company which is expected to last four (4) hours or longer, or

   b. Any sustained service interruption scheduled by the Company which is expected to affect twenty-five (25) or more customers.

   Sustained Reportable Incident shall be defined as any service interruption lasting more than five (5) minutes.

B. Customer Notification Requirements:

1. Reasonable effort will be made to notify affected customers at least forty-

eight (48) hours prior to a Scheduled Service Interruption. Scheduled Service Interruptions that will occur on a Monday will require customer notification on the previous Thursday.

2. In the event of an emergency causing the Company to take a Scheduled Service Interruption in less than forty-eight (48) hours, customers will be notified as soon as practical.

C. Commission Notification Requirements:

1. Scheduled Service Interruption:

a. The Commission will be notified at least forty-eight (48) hours prior to a Scheduled Service Interruption. Scheduled Service Interruptions that will occur on a Monday will require Commission notification on the previous Thursday.

b. In the event of an emergency causing the Company to take a Scheduled Service Interruption in less than forty-eight (48) hours, the Commission will be notified as soon as practical.

2. Nonscheduled Service Interruption:

a. The Commission will be notified within two (2) hours of the known commencement of a Reportable Incident using the Commission's Service Interruption Reporting Telephone number (SIRT). Within 24 hours, the Company will follow up with an email report in conformance with Chapter 3, Section 27(f) of the Commission's Rules.

b. Reports to the Commission shall include, but not be limited to:

i. Location and geographic extent;

ii. Damage assessment, explaining the risks and likely effects on the public, the utility's customers, other utilities and telecommunications services;

iii. Date and time the service interruption began;

iv. Number of customers or individuals affected;

v. Cause, if known;

vi. Estimated time of service restoration and basis for estimate;

vii. Any deaths or injuries;

viii. Efforts being undertaken to restore service;

ix. Efforts being undertaken to assist affected individuals;

x. Other governmental agencies notified;

xi. Contact information for reporting individual(s)

xii. If the event is ongoing, the time interval until the Commission will be updated; and

xiii. Any other information that may be necessary to assess threats or damage.

D. Commission Reporting Requirements:

1. Quarterly reports of all Service Interruptions greater than five minutes other than meter testing or change outs will be filed with the Commission within 30 days after the end of each calendar quarter in conformance with Chapter 3, Section 28 of the Commission's Rules.
2. These records shall be retained by the Company for a minimum of six years.
3. The Company shall annually review its Service Interruption Reporting Plan with any proposed modifications and definitions of major or minor service interruptions specific to the utility's system, filed with the Commission by May 1. If, after the Company's review, there is no change to the Service Interruption Reporting Plan, the Company shall so notify the Commission by letter by May 1.

E. Reportable Incident Contact Information:

1. The Company shall submit a list of contact personnel (names and phone numbers) to be contacted during a Major Reportable Incident.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 170

SERVICE INTERRUPTION REPORTING PLAN Rate 106

2. The contact list shall be reviewed by Montana-Dakota and updated when necessary. The Company will also confirm the list remains current by notifying the Commission by January 1 and July 1 of each calendar year.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 185

ELECTRIC METER TESTING PROGRAM
Rate 115

APPLICABILITY:

This rate schedule specifies the protocol to be followed for the testing of electric meters in accordance with Chapter 3, Section 18 of the Commission Procedural Rules and Regulations (Commission Rules).

NEW METERS:

A sampling of 5% of new meters will be tested at full load and at light load. If any meter is found to be off more than ±1%, the entire lot will be tested or rejected.

RESIDENTIAL WATTHOUR METERS IN SERVICE:

1. A random selection of meters from each decade – 1980's, 1990's, etc., will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense. At the time the random selection is made, meters less than five years old and active meters that have been tested in the last five years, will be excluded from the population to be randomly sampled.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 96% of the meters shall be not more than +/- 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 96% of the meters in a given vintage class fail to meet the requirements of +/- 2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of four years. In the event the meter type failing the +/- 2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

COMMERICAL WATTHOUR METER IN SERVICE:

1. A random selection of solid state meters from each decade – 1980's, 1990's, etc. will be tested annually at full load and light load. The sample size will depend on

lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense. At the time the random selection is made, meters less than five years old and active meters that have been tested in the last five years, will be excluded from the population to be randomly sampled.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 98% of the meters shall be not more than +/- 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 98% of the meters in a given vintage class fail to meet the requirements of +/- 2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of two years. In the event the meter type failing the +/- 2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of two years rather than the entire vintage class.

INDUSTRIAL WATTHOUR METERS IN SERVICE:

1. A random selection of solid state meters from each decade – 1980's, 1990's, etc. will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense. At the time the random selection is made, meters less than five years old and active meters that have been tested in the last five years, will be excluded from the population to be randomly sampled.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 99% of the meters shall be not more than +/- 2% in error at both light load and full load, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

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

State of Wyoming
Electric Rate Schedule

ELECTRIC METER TESTING PROGRAM
Rate 115

4. Whenever it is found that less than 99% of the meters fail to meet these requirements, the entire vintage class will be tested and adjusted or, if more economic, replaced within two years. In the event the meter type failing the +/- 2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of two years rather than the entire vintage class.

METER TEST EQUIPMENT:

1. All equipment used for testing and calibration shall be cared for and maintained as recommended in the manufacturer's operating and maintenance manuals. Appropriate carrying cases designed for the purpose shall be used when such equipment is transported to and from its normal service location.

2. Meters and other equipment which will be used as a reference standard to certify other equipment shall be kept in a temperature stable environment and shall be calibrated annually except as noted herein.

3. Meters and other equipment which are used as a reference standard shall only be used for calibration purposes, and shall not be used for trouble shooting, corrective maintenance or any other activity which might jeopardize the integrity of the instrument for calibration accuracy.

4. Calibration of the items used by the utility for reference standards shall be accomplished by an instrument with a higher degree of accuracy than the item being calibrated with the accuracy of said instrument being traceable to the National Institute of Standards and Technology (NIST).

5. Current transformers are burden tested at the time the meter is tested. A field test set is connected in series with the secondary of the metering current transformer, at the test switch. The test switch is opened, and the transformer secondary is shorted out. Each current transformer is tested first at the maximum burden, and, if the current drops, the burden is decreased until no change is observed. Appendices with the test set are used to evaluate the results to determine if the current transformer is performing satisfactorily.

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

State of Wyoming
Electric Rate Schedule

ELECTRIC METER TESTING PROGRAM
Rate 115

6. Voltage transformers are tested by applying a test voltage to determine if the appropriate ratio is obtained.

7. Whenever any electric meter is tested, the test record shall be preserved, including the information necessary for identifying the meter, the reason for making the test, the reading of the meter upon removal from service and the result of the test, together with all data taken at the time of the test in sufficiently complete form to permit the convenient checking of the methods employed and the calculations for the life of the meter.

8. The Company shall perform meter testing using the equipment identified in the table below.

Type	Manufacturer	Used for	Degree of Accuracy	Calibration Interval
RM-17	Radian	Watt-hour Meter Standard	±0.05%	12 Months
RB-20	Radian	Watt-hour Meter Standard	±0.05%	12 Months

9. The Company shall perform calibration checks on the above identified testing equipment using the equipment identified in the table below.

Type	Manufacturer	Used to Test Equipment Types	Degree of Accuracy	Calibration Interval
RD-21	Scientific Columbus	RM-17 RB-20	See Note 1/	12 Months

Note 1/:
Accuracy: Errors expressed in percent of reading for normal operating conditions. Guaranteed accuracy specification includes stability, traceability, uncertainty, power factor, and test system errors.

1. Normal Operating Conditions:
   i. Ambient Temperature: -20°C to 70°C (-4°F to 158°F)
   ii. Relative Humidity: 0% to 95%
   iii. Auxiliary Power Voltage: 60 – 600 volts (Autoranging)
   iv. Frequency: 45 to 65 Hz
   v. Orientation: Any
2. Influences Affecting Accuracy:
   i. Temperature influence outside normal operating temperature range per °C: ±0.0005%
   ii. For Power Factors of 100% and 50% output for Whrs, VARhrs, VAhrs: no impact on accuracy
   iii. For power factor of <0.5 (PF between - 60° and -90°, then guaranteed accuracy is ±0.02%/PF.

10. These instruments are in turn calibrated with higher degree accuracy instruments annually. The highest degree accuracy instruments will be delivered to a manufacturer's facility once each year for calibration with their instruments that are directly traceable to the National Institute of Standards and Technology (NIST).

11. The referenced Military Standards are available for review by the customer by contacting the Company to discuss by phone or to arrange an appointment at the Company's Sheridan office.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
1st Revised Sheet No. 190
Canceling Original Sheet No. 190

AUTOPAY PLAN
Rate 122

AVAILABILITY:

The AutoPay Plan provides customers the option to automatically have their electric service bill, including miscellaneous charges, deducted from their checking account. This option is available in all communities served by the Company to all customers who voluntarily agree to participate in the AutoPay Plan and who have not issued two or more NSF checks to the Company in the preceding 12 month period and are not currently utilizing the Low Income Energy Assistance Program (LIEAP).

GENERAL TERMS AND CONDITIONS:

1. All provisions set forth in customer's otherwise applicable standard rate schedule shall apply.

2. The Company will issue a bill each month to the customer.

3. The bill will indicate that the amount shown in the "Amount Due" column will be automatically deducted from the customer's checking account each month on the due date indicated on the customer's bill.

4. All customers who accept the AutoPay Plan shall sign an authorization form.

5. The Company has the right to remove a customer from the AutoPay Plan if the financial institution has advised the Company of two NSF check instances within the preceding 12 month period. Thereafter, customer shall be again eligible to participate in the AutoPay Plan in the future providing that the customer has complied with the "Availability" section above.

6. Customers utilizing the AutoPay Plan who subsequently use the LIEAP will be removed from the AutoPay Plan by the Company.

7. The customer may cancel the use of the AutoPay Plan option by notifying the Company in writing.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 200

BALANCED BILLING PLAN
Rate 125

1. SCOPE

A. The Plan provides electric customers with a method of paying for electric usage to avoid the highs and lows associated with normal monthly billing. The customer's monthly bill is computed by taking an average of the usage during the previous twelve months. Current energy rates are then applied to this average monthly usage to calculate the current payment due. Qualified customers with less than 12 month's history at their current premise are also allowed to enroll in the Plan.

B. Monthly bills rendered under this Plan, as indicated in A. above, will be based upon a moving average consumption and will normally change each month. The moving average will change slightly each month and thus appropriate dollar adjustments will be made to the billed amount each month.

C. The provisions of this Plan are applicable to all residential customers in Wyoming. Certain nonresidential electric customers served in Wyoming may qualify. Accordingly, the following nonresidential customers do not qualify for this Plan:

1. Industrial, municipal or interdepartmental electric customers.

2. Electric customers with demand meters.

3. Combination customers who have electric demand meters neither the gas and/or electric usage qualifies for the Plan.

4. Interruptible or otherwise controlled customers.

5. Seasonal, short-term or temporary customers.

6. Customers whose accounts are delinquent and who have not signed a Deferred Payment Agreement.

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

State of Wyoming
Electric Rate Schedule

BALANCED BILLING PLAN
Rate 125

7. Customers whose usage patterns are not sufficiently predictable so as to permit estimation on an annual basis with a reasonable degree of certainty.

2. PROCEDURE

A. Customers must contact Company to request enrollment in the Balanced Billing Plan.

B. If the customer's account is current and otherwise qualifies for enrollment in the Plan as provided in Section I.C., the customer will be so informed at the time of customer's request and the customer's account record in the Customer Information System will be so coded.

C. As indicated in Section 1.C.6., customers who are delinquent cannot qualify for the Plan unless they are able to pay any amounts past due or enter into a Deferred Payment Agreement with the Company. The customer agrees to pay a reasonable fixed amount each month in addition to the Balanced Billing Plan payment amount until such arrears are paid in full.

D. Customers enrolled in the Plan will continue to be billed under the Plan provisions until they request removal or they are sixty days in arrears and are removed from the Plan by the Company.

E. If a customer desires to be removed from the Plan, customer must contact Company to request withdrawal from the Plan. Removal from plan will be effective following contact regarding withdrawal. Upon such removal the total unpaid balance becomes due at the next billing cycle. If a credit balance exists it may be refunded or applied to the next cycle billing, at the customer's discretion.

F. If a customer is removed from the Plan due to delinquency as indicated above, the total unpaid balance in their account becomes due and payable.

Montana-Dakota Utilities Co.

Wyoming Electric Tariffs - Proposed

Docket No. 20004-___-ER-25

Appendix B

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Title Sheet

TITLE SHEET

WYOMING P.S.C. TARIFF NO. 2
Including
Schedule of Rates for Electric Service
and
Rules

OF

MONTANA-DAKOTA UTILITIES CO.,

400 N 4th Street

BISMARCK, NORTH DAKOTA 58501

Filed with the

WYOMING PUBLIC SERVICE COMMISSION

Date Filed:	June 30, 2025	**Effective Date:**	Service rendered on and after
Issued By:	Travis R. Jacobson Vice President– Regulatory Affairs	**Docket No.:**	

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 1

TABLE OF CONTENTS

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 3

COMMUNITIES SERVED

COMMUNITIES SERVED

Acme	Ranchester
Big Horn	*Sheridan
Dayton	Story

*Designates District Office

Montana-Dakota Sheridan District Office
2324 Dry Ranch Road
Sheridan, WY 82801
1.800.638.3278

Date Filed:	June 30, 2025	**Effective Date:**	Service rendered on and after
Issued By:	Travis R. Jacobson Vice President– Regulatory Affairs	**Docket No.:**	

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 4

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Demand Charge Per Kw	Energy Charge Per Kwh	PSCA Per Kwh 1/	RSIR 2/	Total Per Kwh
Residential Rate 10	6	$1.160 per day				0.00%	
Energy Charge:				$0.06291	$0.04422		$0.10713
Special Residential Controlled Rate 11	10	$0.194 per day				0.00%	
Energy Charge:				$0.04733	$0.04422		$0.09155
Small General Rate 20	20						
Demand Metered							
Primary Service:		$3.000 per day				0.00%	
Demand Charge:							
First 10 Kw or less of billing demand			$8.76				
Over 10 Kw per month of billing demand			$14.75				
Energy Charge:				$0.02804	$0.03902		$0.06706
Secondary Service:		$1.380 per day				0.00%	
Demand Charge:							
First 10 Kw or less of billing demand			$9.55				
Over 10 Kw per month of billing demand			$15.45				
Energy Charge:				$0.02992	$0.04422		$0.07414
Small General Rate 20	20	$1.380 per day				0.00%	
Non Demand Metered							
Energy Charge				$0.03771	$0.04422		$0.08193
Outdoor Lighting Rate 24	30					0.00%	
Energy Charge				$0.03323	$0.04422		$0.07745
Irrigation Power Rate 25	35	$2.868 per day				0.00%	
Demand Charge			$11.50				
Energy Charge				$0.02737	$0.04422		$0.07159
Irrigation Power Time of Day Rate 26	37	$2.750 per day				0.00%	
Demand Charge:							
On-Peak Demand			$13.50				
Off-Peak Demand			$5.00				
Energy Charge				$0.04624	$0.04422		$0.09046

1/ Sheet No. 58
2/ Sheet No. 60. Applicable to amounts billed under Basic Service Charge, Energy Charge, and Demand Charges.

Date Filed: June 30, 2025

Effective Date: Service rendered on and after

Issued By: Travis R. Jacobson
Vice President - Regulatory Affairs

Docket No:

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 4.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Demand Charge Per Kw	Energy Charge Per Kwh	PSCA Per Kwh 1/	RSIR 2/	Total Per Kwh
Large Power Standby Rate 37	40					0.00%	
Primary Serivce:		$300.00 per mo.					
Contract Demand Charge			$15.64				
Energy Charge:				$0.01131	$0.03902		$0.05033
Secondary Service:		$95.00 per mo.					
Contract Demand Charge			$15.28				
Energy Charge				$0.00479	$0.04422		$0.04901
Interruptible Large Power Demand Response Rate 38	43					0.00%	
Primary Service		$300.00 per mo.					
Demand Charge			$16.14				
Demand Response Credit			$2.75				
Energy Charge				0.01131	$0.03902		$0.05033
Secondary Service:		$95.00 per mo.					
Demand Charge			$15.78				
Demand Response Credit			$2.75				
Energy Charge				0.00479	$0.04422		$0.04901
Large General Rate 39	45					0.00%	
Primary Service		$300.00 per mo.					
Demand Charge			$16.14				
Energy Charge				$0.01131	$0.03902		$0.05033
Secondary Service:		$95.00 per mo.					
Demand Charge			$15.78				
Energy Charge				$0.00479	$0.04422		$0.04901
Public Lighting Rate 41	50					0.00%	
Energy Charge				$0.07230	$0.04422		$0.11652
Parallel Generation Rate 57	70					0.00%	
Partial Requirement:							
Single Phase		$3.30 per mo.					
Three Phase		$9.34 per mo.					
Energy Payment				$0.03448	Not Applicable		$0.03448
Parallel Generation							
Single Phase		$13.68 per mo.					
Three Phase		$17.25 per mo.					
Capacity Payment			$8.29				
Energy Payment				$0.03448	Not Applicable		$0.03448

1/ Sheet No. 58
2/ Sheet No. 60. Applicable to amounts billed under Basic Service Charge, Energy Charge, and Demand Charges.

Date Filed: June 30, 2025

Effective Date: Service rendered on and after

Issued By: Travis R. Jacobson
Vice President - Regulatory Affairs

Docket No:

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 6

RESIDENTIAL ELECTRIC SERVICE
Rate 10

AVAILABILITY:

In all communities served for single-phase residential electric service through one meter in a single private residence for all domestic uses.

RATE:

Basic Service Charge:	$1.160 per day
Energy Charge:	6.291¢ per Kwh

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 10

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11 (CLOSED TO NEW CUSTOMERS)

AVAILABILITY:

In all communities served for single-phase residential electric service customers who operate Company approved interruptible electric space heating equipment so arranged to allow remote operation by the Company and subject to the Company's ability to control such equipment. This rate schedule is restricted to active services installed on a customer's premise on or before August 2, 2022.

Controlled electric water heating service is also available under this rate in conjunction with controlled space heating. The customer's primary source of space heating shall be electric and the customer shall be responsible for providing a secondary source of space heating. The main energy used in backup systems cannot be firm electric service. Domestic uses other than controlled space heating and controlled water heating will be served under Residential Electric Service Rate 10.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving water heating and space heating facilities with no provision for connecting other loads thereto. The customer's secondary system controls, circulating fans and pumps and all other alternate fuel related equipment shall be served as uncontrolled load. Unless otherwise specified by the Company, the point of delivery and service voltage for this service shall be the same as for the customer's other electric service.

RATE:

Basic Service Charge:	$0.194 per day
Energy Charge:	4.733¢ per Kwh

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 10.1

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11 (CLOSED TO NEW CUSTOMERS)

MINIMUM BILL:

Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

1. Electric space and water heating equipment shall be designed to operate at a nominal voltage of 208, 240, or 277 volts, shall be separately metered and separately circuited, shall be permanently installed and the electric heating equipment shall be the principal source of space heating.

2. All installations must meet the minimum standards of the National Electrical Code so that the equipment will operate in a satisfactory manner and not interfere with other operations of the Company's system. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations for heating to make sure their equipment, insulation and building construction will meet requirements and receive adequate service.

3. The customer must connect the interruptible electrical circuit(s) so as to allow interruptions through a Company owned contactor(s). A maximum of two contactors shall be provided by Company up to a maximum rating of 5 amps for one and 30 amps for the other. The customer must wire into a connection point designated by Company to allow installation of control equipment by Company. The customer must provide a continuous 240 volt AC power source at the connection point for operation of the Company's control system.

4. The Company recommends that the installed capacity of electric water heating equipment be sufficient to provide the required volume of hot water giving consideration to the interruptions to be experienced and to permit maximum utilization of the rate for the benefit of the customer.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 10.2

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11 (CLOSED TO NEW CUSTOMERS)

5. Service hereunder shall be available at the time control equipment is actually installed by the Company.

6. The Company shall not be liable for loss or damage caused by interruption of service.

7. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 15

RENEWABLE ENERGY RIDER
Rate 15

AVAILABILITY:
In all communities served by the Company in the State of Wyoming. The Renewable Energy Rider is available on an optional basis to customers receiving service under the Company's Electric Service Rate Schedules.

CHARGE PER BLOCK:

One (1) Block:	$0.01 per month

One Block equals 100 Kwh of Renewable Energy Credit purchases.

MONTHLY BILL:
The Monthly Bill shall be the number of Blocks the customer has agreed to purchase multiplied by the Charge per Block. The Monthly Bill is in addition to all other charges contained in the customer's applicable rate schedule. The Monthly Bill shall be applied to the customer's billing regardless of actual energy consumption.

RENEWABLE ENERGY CREDIT:
A Renewable Energy Credit represents the intangible environmental attributes associated with producing one MWh of electricity from a renewable resource such as wind, solar or biomass. The Company will purchase Renewable Energy Credits as needed to match the number of Blocks purchased under this rate schedule. One Renewable Energy Credit equals 1,000 Kwh (1 MWh) of electricity from a renewable resource. Each Block is equivalent to one-tenth (1/10) of a Renewable Energy Credit.

GENERAL TERMS AND CONDITIONS:

1. Customers may apply for this rate any time during the year.

2. The Company will purchase Renewable Energy Credits to match purchases under this rate schedule. Due to timing differences, the purchase of Renewable Energy Credits may not directly correspond to customer purchases in an individual 12 month period.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 15.1

RENEWABLE ENERGY RIDER
Rate 15

3. All funds collected and expenses associated with this program will be separately identified and tracked. Interest shall be credited in the case of net over collections at one-twelfth of the Commission's Authorized Interest Rate specified in accordance with Chapter 1, Section 3(a)(xvii) of the Wyoming Public Service Commission's Rules. The Charge per Block is subject to change on an annual basis.

4. The commitment to purchase Blocks under this Rider will be for a minimum of a one year period and will continue on a monthly basis thereafter until the customer provides notice to either change or end participation. Requests for early withdrawal due to extenuating circumstances will be considered.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 20

SMALL GENERAL ELECTRIC SERVICE
Rate 20

AVAILABILITY:

In all communities served for all types of general electric service with billing demands of 50 kilowatts or less, except customers covered by special contracts, or other rate schedules applicable to specific services. The customer's wiring must be so arranged that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

RATE:

Demand Metered Service:

Primary Service:

Basic Service Charge:	$3.000 per day
Demand Charge:	
First 10 Kw or less of billing demand	$ 8.76 per Kw
Over 10 Kw per month of billing demand	$14.75 per Kw
Energy Charge:	2.804¢ per Kwh

Secondary Service:

Basic Service Charge:	$1.380 per day
Demand Charge:	
First 10 Kw or less of billing demand	$ 9.55 per Kw
Over 10 Kw per month of billing demand	$15.45 per Kw
Energy Charge:	2.992¢ per Kwh

Non Demand Metered Service:

Basic Service Charge:	$1.380 per day
Energy Charge:	3.771¢ per Kwh

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 20.1

SMALL GENERAL ELECTRIC SERVICE
Rate 20

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the maximum 15-minute measured demand in the current month. Demand will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. All installations must meet the minimum standards of the National Electrical Code so that the equipment will operate in a satisfactory manner, and not interfere with other operations of the Company's system. Architects, contractors and electricians should consult with the Company before

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 20.2

SMALL GENERAL ELECTRIC SERVICE
Rate 20

proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. At its discretion, the Company may install a demand meter on any customer's service whose average monthly usage exceeds 4,000 Kwh or who has an average peak demand greater than 10 Kw in any given twelve month period.

3. Non-metered services. At the Company's discretion, the installation of a meter on a customer's service may not be warranted. In the absence of measuring a customer's use, customers will be billed a predetermined energy use amount each month based on the operating characteristics of the equipment being served, such as Wi-Fi equipment served on Company-owned poles.

4. The primary service rate is applicable to customers that own their own transformers, related equipment, and distribution facilities downstream of the meter, satisfactory to the Company so customers can receive service and be metered at primary voltages of 2,400 volts or greater.

5. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 30

OUTDOOR LIGHTING SERVICE
Rate 24

AVAILABILITY:

For all outdoor lighting including flood lights, traditional or non-electronic billboard lighting and yard lights in all communities served. Lighting equipment may be Company-owned or customer-owned.

RATE:

Energy Charge: 3.323¢ per Kwh

Kwh shall be computed according to the total rated capacity of the units in use.

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

PAYMENT:

Bills 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 or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

1. When service is not metered, the bill shall be computed on a daily basis, utilizing the minimum service requirement of 4,000 hours annually, and billed monthly to the customer.

2. Applicable to Company-owned facilities:
   a. The Company will install, own and operate the flood light(s), and yardlight(s) including a suitable reflector, bracket for mounting and automatic device to control operating hours set to operate from dusk to dawn.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 30.1

OUTDOOR LIGHTING SERVICE
Rate 24

b. The Company will convert mercury vapor light units to high pressure sodium upon failure of existing mercury vapor units.

c. The light may be mounted on existing poles owned or controlled by the Company or on a pole owned by the customer or other mounting point suitable for installation of the light. The conductors will be extended 100 feet per unit free of charge, but the customer shall pay for the extra cost of extensions of more than 100 feet per unit.

d. For Company-owned facilities, a monthly rental charge shall be rendered for each unit installed in addition to the energy charge. The customer should consult with the Company for such costs.

e. The Company will maintain the Company-installed and owned facilities when notified by customer or when noticed by Company personnel. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the customer for the cost of repair and replacement.

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 35

IRRIGATION POWER SERVICE
Rate 25

AVAILABILITY:

For all irrigation power service, except customers choosing the Irrigation Power Service – Optional Time of Day Rate 26.

RATE:

Basic Service Charge:	$2.868 per day
Demand Charge:	$11.50 per Kw
Energy Charge:	2.737¢ per Kwh

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL: Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the maximum 15-minute measured demand in the current month. Demand will be determined to the nearest one-tenth kilowatt.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 35.1

IRRIGATION POWER SERVICE
Rate 25

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. Individual motors having a rating in excess of 10 horsepower must be three-phase. All wiring and other facilities beyond the point of metering shall be owned, operated, and maintained by the customer.

2. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 37

IRRIGATION POWER SERVICE – OPTIONAL TIME OF DAY
Rate 26

AVAILABILITY:

For irrigation power service where customer chooses the optional time differentiated schedule for a minimum period of 12 months.

RATE:

Basic Service Charge: $2.750 per day

Demand Charge:

On-Peak Demand: $13.50 per Kw
Demand measured during peak hours designated as 4 p.m. to 6 p.m. local time Monday through Friday.

Off-Peak Demand: $ 5.00 per Kw
Demand measured during all hours not covered by the on-peak rating period.

Energy Charge: 4.624¢ per Kwh

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL: Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 37.1

IRRIGATION POWER SERVICE – OPTIONAL TIME OF DAY
Rate 26

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the maximum 15-minute measured demand in the off-peak period and the maximum 15-minute measured demand in the on-peak period in the current month. Demand will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. Individual motors having a rating in excess of 10 horsepower must be three-phase. All wiring and other facilities beyond the point of metering shall be owned, operated, and maintained by the customer.

2. A customer choosing the optional time of day schedule shall remain on that schedule for a twelve month period.

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 40

LARGE POWER STANDBY SERVICE
Rate 37

AVAILABILITY:

This rate is applicable for power and lighting requirements of customers having their own generating facilities desiring standby power of 200 kilowatts or more through a permanent connection to be used in the event of failure of such generating facilities, or for use during the maintenance and overhaul of such facilities.

RATE:

Primary Service:

Basic Service Charge:	$300.00 per month
Contract Demand Charge:	$15.64 per Kw
Energy Charge:	1.131¢ per Kwh

Secondary Service:

Basic Service Charge:	$95.00 per month
Contract Demand Charge:	$15.28 per Kw
Energy Charge:	0.479¢ per Kwh

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge plus Contract Demand Charge (Contract Demand minimum).

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 40.1

LARGE POWER STANDBY SERVICE
Rate 37

PAYMENT:

Bills 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 or any amendments or alterations thereto.

DETERMINATION OF CONTRACT DEMAND:

The demand in kilowatts for billing purposes shall be the greater of either the maximum 15-minute measured demand in the current month or the contract demand in kilowatts. Measured demand will be determined to the nearest one-tenth kilowatt. The Company will require the customer to contract for additional standby and supplementary capacity if the customer exceeds the contract demand in any one month. Such measured demand shall become the new contract demand commencing with the month in which measured and thereafter for the eleven succeeding months, after which the customer and Company will redetermine full service requirements

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

CONTRACT TERMS:

The customer agrees to contract for service under the Large Power Standby Service rate for a minimum period of one year. If the customer fails to continue service for the initial annual period, the customer will be billed for the difference between the customer's actual billing under Rate 37 and what would have been billed under Rate 39.

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

State of Wyoming
Electric Rate Schedule

LARGE POWER STANDBY SERVICE
Rate 37

GENERAL TERMS AND CONDITIONS:

1. The customer will contract for capacity adequate to supply the entire electrical requirements for which the Company's service may be used. Contract demand will be no less than what the Company will be required to supply in case of customer equipment malfunction.

2. No customer may connect an independent source of power in parallel with the Company's system without prior written consent of the Company. Any customer desiring to generate in parallel shall execute a contract with the Company that contains terms and provisions regarding metering, billing, technical, and operating parameters for the customer's independent source of power.

3. The customer shall be subject to charges for interconnection costs, as defined in the Energy Sales Agreement.

4. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 43

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

AVAILABILITY:

In all communities served for power to customers having a demand of 500 Kw or more where at least 75 percent is available for interruption up to 100 hours annually. Electric energy for the interruptible load shall be supplied through a common customer meter used to serve the customer's total electrical load.

RATE:

Primary Service:

Basic Service Charge:	$300.00 per month
Demand Charge:	$16.14 per Kw of Billing Demand
Demand Response Credit:	$2.75 per Interruptible Kw of Interruptible Load
Energy Charge:	1.131¢ per Kwh

Secondary Service:

Basic Service Charge:	$95.00 per month
Demand Charge:	$15.78 per Kw of Billing Demand
Demand Response Credit:	$2.75 per Interruptible Kw of Interruptible Load
Energy Charge:	0.479¢ per Kwh

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge plus the Demand Charge (500 Kw minimum).

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 43.1

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

PAYMENT:

Bills 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 or any amendments or alterations thereto.

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 500 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to Conditions of Service Rate 100, Section 700.

DETERMINATION OF INTERRUPTIBLE KW:

Interruptible Kw shall be the Billing Demand less the Baseline Non-Interruptible Load.

BASELINE NON-INTERRUPTIBLE LOAD:

Annually, customers must select a Baseline Non-Interruptible Load in Kw which shall not be subject to interruption. Customers must select a Baseline Non-Interruptible Load that results in at least 75% expected load being interrupted.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. The customer shall execute an electric service agreement with the Company which shall include a minimum term of service, the Baseline Non-Interruptible Load, and any additional customer costs incurred by Company for facilities, such as substations, electric lines, meters, switching devices, and circuit breakers that are necessary to provide service under this rate schedule.

a. Electric service agreements shall also include contact information, method(s) of communication to initiate demand response event(s), and test procedures for calculating Baseline, Non-Interruptible Load.

2. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required electric service agreement. Enhancements and/or modifications to equipment may be required to ensure equipment functionality and/or communication with the Company's fixed network facilities. Such enhancements and/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.

3. Customer will be required to interrupt service within 30 minutes of the Company's notification to interrupt service unless agreed otherwise by the parties.

4. The penalty for non-performance by customer in response to a Company request to interrupt will be $12.00 per Kw applicable to the Interruptible Kw specified in the electric service agreement with the Company. After a second failure to perform within a 12-month period, the customer may be moved to the otherwise applicable rate at the Company's discretion.

5. The Company may request a summer and winter performance test each year, lasting up to one hour in length, to test the customer's interruption capability and Baseline Non-Interruptible Load. Scheduled performance tests shall not count against the 100 hour limit

6. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

7. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 45

LARGE GENERAL ELECTRIC SERVICE
Rate 39

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 kilowatts of billing demand, except customers covered by special contracts. The customer's wiring must be so arranged that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

RATE:

Primary Service:

Basic Service Charge:	$300.00 per month
Demand Charge:	$16.14 per Kw of billing demand
Energy Charge:	1.131¢ per Kwh

Secondary Service:

Basic Service Charge:	$95.00 per month
Demand Charge:	$15.78 per Kw of billing demand
Energy Charge:	0.479¢ per Kwh

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge plus Demand Charge.

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

State of Wyoming
Electric Rate Schedule

LARGE GENERAL ELECTRIC SERVICE
Rate 39

PAYMENT:

Bills 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 or any amendments or alterations thereto.

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15-minute measured demand in the current month or 50 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to Conditions of Service Rate 100, Section 700.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. The primary service rate is applicable to customers that own their own transformers, related equipment, and distribution facilities downstream of the meter, satisfactory to the Company so customers can receive service and be metered at primary voltages of 2,400 volts or greater.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 45.2

LARGE GENERAL ELECTRIC SERVICE
Rate 39

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 50

PUBLIC LIGHTING SERVICE
Rate 41

AVAILABILITY:

For the lighting of streets, alleys, and other road right of ways in Sheridan, Dayton and Ranchester, Wyoming. Service will be provided all night every night with a minimum service requirement of 4,000 hours annually.

RATE:

Energy Charge: 7.230¢ per Kwh for all energy used

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

Facilities Charge per unit per month:
Applicable to lighting facilities owned, installed, and maintained by the Company.

LED, Overhead Conductor, Distribution Pole	$ 6.70
LED, Overhead Conductor, Street Light Pole	$12.80
LED, Underground Conductor, Distribution Pole	$ 8.60
LED, Underground Conductor, Street Light Pole	$14.70
Wood Pole	$ 7.00

PAYMENT:

Bills 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 or any amendments or alterations thereto.

GENERAL TERMS AND CONDITIONS:

1. When service is not metered, the bill shall be computed on a daily basis, utilizing the minimum service requirement of 4,000 hours annually, and billed monthly to the customer.

2. In Company-owned street lighting systems, a monthly rental charge shall be rendered in addition to the energy charge. The customer should consult with the Company for such costs.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 50.1

PUBLIC LIGHTING SERVICE
Rate 41

3. For Company-owned public lighting systems, the Company will maintain the facilities and change the light bulbs when notified by the customer that they are burned out except when the facilities are damaged or destroyed by vandalism, malicious mischief by third parties, or willful negligence on the part of the customer. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the customer for the cost of repair and replacement.

   The Company will convert mercury vapor light units to high pressure sodium upon failure of existing mercury vapor units.

4. In customer-owned street lighting systems, an additional charge will be made to cover lamp replacements, materials and labor whenever such services are supplied by the Company.

5. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 55

POWER SUPPLY COST ADJUSTMENT
Rate 50

1. APPLICABILITY:
   This rate schedule constitutes a Power Supply Cost Adjustment (PSCA) provision and specifies the procedure to be utilized to adjust the rates for fuel and purchased power sold under Montana-Dakota's rate schedules in order to reflect the recovery (refund) of the Power Supply Balancing Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:
   The effective date of the PSCA shall be service rendered on and after May 1 each year unless the Wyoming Public Service Commission (Commission) shall otherwise order. The Company will file an application with the Commission to implement the PSCA rate on an interim basis and, if approved by the Commission, the PSCA rate shall continue until a final order is issued by the Commission establishing an effective PSCA rate.

3. POWER SUPPLY COST ADJUSTMENT:
   a. The annual PSCA shall be calculated separately for primary service and secondary service and reflect changes in Montana-Dakota's cost of power supply as compared to the base cost of power supply established in a general rate case for each class.

   b. The cost of power supply shall be the sum of the approved costs incurred in obtaining fuel and purchased power supply for use by all customers served under retail sales rate schedules for the twelve month period ending December 31 each year.

   c. The cost of power supply shall include the following costs for fuel and purchased power supply:

      1. Fuel and fuel handling costs recorded in Account No. 501 and reagent costs recorded in Account 502;
      2. Demand, energy, ancillary services and transmission charges recorded in Account 555; and
      3. Regional Marketing Administration expenses recorded in Account 575; and
      4. The cost of new or existing governmental impositions for electric generation plant emissions, including but not limited to $S0_2$ allowances, carbon taxes and/or carbon allowances and other governmental initiatives related to electric generation plant emissions. Prior to

including any new governmental impositions in the PSCA, the Company will receive approval from the Commission.

d. The base cost of power supply shall consist of all power supply costs established in a general rate case for primary and secondary service stated on a Kwh basis. The base cost of power supply established in Docket No. 20004-___-ER-25 is as follows:

Base Cost of Power Supply Expense	Primary	Secondary
Fuel	1.056¢	1.067¢
Purchased Power	2.846¢	3.355¢
Total	3.902¢	4.422¢

e. The calculation of the power supply cost adjustment is shown on Sheet No. 55.4.

4. POWER SUPPLY BALANCING ACCOUNT:
   a. Items to be included in the Power Supply Balancing Account are:

      1. Amounts under recovered or over recovered for fuel;

      2. Amounts under recovered or over recovered for purchased power supplies each month;

      3. Refunds received with respect to fuel and purchased power supply shall be credited to the Power Supply Balancing Account; and

      4. Interest on the net over or under collected balance in accordance with Subsection 4.b.4.

   b. The amount to be included in the Power Supply Balancing Account in order to reflect the items specified in Subsection 4.a.1-4 shall be calculated as follows:

      1. Montana-Dakota shall first determine each month the unit cost for that month's fuel cost and purchased power costs by PSCA class:

a. Fuel costs shall be allocated to each class based on sales volumes for the month adjusted for the applicable loss factor from the most recently approved general rate case; and

b. Purchased power energy shall be allocated to each class based on sales volumes for the month adjusted for the applicable loss factor from the most recently approved general rate case. Purchased power demand and transmission charges shall be allocated to each class based on the average and excess demand factor that will be updated annually.

2. Montana-Dakota shall then subtract from each month's unit cost (fuel and purchased power) the total cost in rates as set forth in Subsection 6:
   a. For fuel, the difference (which may be positive or negative) shall be multiplied by 85 percent and by the Kwh sold during that month under each applicable rate schedule. The resulting amounts shall be reflected in the Balancing Account (Account 182.3) for primary and secondary service; and
   b. For purchased power, the difference (which may be positive or negative) shall be multiplied by 95 percent and by the Kwh sold during that month under each applicable rate schedule. The resulting amounts shall be reflected in the Balancing Account for primary and secondary service.

3. The amounts in the Power Supply Balancing Account shall be decreased each month by an amount determined by multiplying the currently effective Surcharge Adjustment included in rates for that month by the Kwh sales during that month under each rate schedule. The amount in the account shall be increased in the event the adjustment is a negative amount.

4. The balance in Account 182.3, to which interest will apply, will be the balance at the end of the immediately preceding month. Interest shall be applied to the net over or under collected balance at one-twelfth of the

Commission's Authorized Interest Rate specified in Chapter 1, Section 3(a)(xvii) of the Commission's Rules and recorded in Account 182.3.

The amount amortized each month shall be applied pro rata between the amounts in the Power Supply Balancing Account specified in Subsection 4.a.1. and 2. and the amount related to carrying charges specified in Subsection 4.a.

5. TIME AND MANNER OF FILING:
   a. Each application by Montana-Dakota shall be made by means of revised PSCA and rate schedule tariff sheets identifying the amounts of the adjustments and the resulting currently effective PSCA rates.

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

   c. The application shall be made 60 days prior to the implementation date of May 1 each year.

6. POWER SUPPLY COST ADJUSTMENT:
   The total power supply cost equals 3.902¢ per Kwh for the Primary Service PSCA rate class and 4.422¢ per Kwh for the Secondary Service PSCA rate class. The currently effective PSCA applied to each rate schedule and shown separately on the consumer bill is:

	Primary	Secondary
Base Cost of Power Supply	3.902¢	4.422¢
Power Supply Cost Adjustment	0.000	0.000
Power Supply Balancing Account Adjustment	0.000	0.000
Total PSCA	3.902¢	4.422¢

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 55.4

POWER SUPPLY COST ADJUSTMENT
Rate 50

	Total	Primary	Secondary
Fuel			
501.1 Fuel	$2,362,294	$201,429	$2,160,865
501.4 Fuel Handling	209,716	17,882	191,834
502. Reagents	549,830	46,883	502,947
Total Fuel	$3,121,840	$266,194	$2,855,646
Kwh Sales	292,769,653	25,217,920	267,551,733
Cost per Kwh		$0.01056	$0.01067
Base Fuel Cost		0.01056	0.01067
Difference from Base		$0.000000	$0.000000
Total Change from Base	$0	$0	$0
Amount to be recovered (refunded) from customers (85%)		$0	$0
Purchased Power			
555.1 Energy	$4,176,744	$356,144	$3,820,600
555.6 Capacity	2,826,007	185,168	2,640,839
555.6 Transmission	2,692,378	176,412	2,515,966
Purchased Power	$9,695,129	$717,724	$8,977,405
Kwh Sales	292,769,653	25,217,920	267,551,733
Cost per Kwh		$0.02846	$0.03355
Base Cost of Purchased Power		0.02846	0.03355
Difference from Base		$0.00000	$0.00000
Total Change from Base	$0	$0	$0
Amount to be recovered (refunded) from customers (95%)		$0	$0
Power Suppy Cost Adjustment			
Balance @ 12/31/__		$0	$0
Under (Over) Recovery			
Fuel		$0	$0
Purchased Power		0	0
Net		$0	$0
Amortization			
Interest			
Balancing Account balance @ 12/31/__		$0	$0
Estimated amortization Jan-April			
Net Balance		$0	$0
Projected Kwh sales		25,217,920	267,551,733
PSCA Adjustment		$0.0000	$0.0000
Base PSCA		$0.03902	$0.04422
PSCA Adjustment		0.00000	0.00000
Total PSCA		$0.03902	$0.04422

Date Filed: June 30, 2025

Effective Date: Service rendered on and after

Issued By: Travis R. Jacobson
Vice President – Regulatory Affairs

Docket No.:

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 60

RELIABILITY AND SAFETY INFRASTRUCTURE RIDER
Rate 55

APPLICABILITY:

This rate schedule provides a Reliability and Safety Infrastructure Rider (RSIR) recovery mechanism and specifies the procedure utilized to recover the revenue requirement associated with projects designed to improve the reliability and safety of the Company's electric infrastructure in Wyoming. RSIR costs recovered under the rider have been approved by the Commission and may include, but are not limited to, new or modified transmission-level projects specific to the improvement of power delivery and reliability to customers, replacement of pre-1985 underground distribution cables, and upgrades necessary for wildfire mitigation. Costs included in the rider are not reflected in the rates established in the most recent general rate case.

RELIABILITY AND SAFETY INFRASTRUCTURE RIDER:

1. The RSIR shall be calculated annually reflecting forecasted costs through year end of the filing year and through November of the following year.

2. The rider shall include a return requirement on the capital investment based on the rate of return authorized in the Company's most recent general electric rate case, in addition to operation and maintenance expenses, depreciation expense, and ad valorem tax expense associated with the eligible projects and a true-up of the previous year's rate.

3. A true-up will reflect any over- or under collection of revenue under the RSIR based on actual expenditures from the preceding twelve month recovery period. Interest shall be applied to the net over or under collection at one-twelfth of the Commission's authorized interest rate specified in accordance with Chapter 1, Section 3(a)(xvii) of the Commission's Rules.

4. The resulting revenue requirement shall be divided by the Total Revenue excluding the Power Supply Cost Adjustment revenue from Montana-Dakota's most recent general electric rate case to determine a percentage adder rate applicable to all rate schedules.

5. The percentage adder shall be applied to the dollars billed under the Basic Service Charges, Energy Charges, and Demand Charges of each rate schedule and identified as its own line on customers' bills.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 60.1

RELIABILITY AND SAFETY INFRASTRUCTURE RIDER
Rate 55

6. When Montana-Dakota files its next general rate case, all project costs shall be removed from the RSIR and included in base rates. Only the true-up component (remaining rider balance) shall remain for recovery through the RSIR to be either collected or returned to customers over a subsequent period.

TIME AND MANNER OF FILING:

1. Each application by Montana-Dakota shall be made by means of a revised RSIR rate and tariff sheet reflecting updated project costs and true-up and the resulting rates.

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

3. The application shall be made 60 days prior to the implementation date of December 1 each year.

RSIR RATE: 0.00%

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 70

PARALLEL GENERATION
Rate 57

AVAILABILITY:

Available to (1) any single or three-phase electric service customer who generates electrical energy in excess of their total energy requirements and who has received qualifying status as a cogenerator or small power producer under Section 201 of the Public Utility Regulatory Policies Act of 1978, defined herein as Parallel Generation Customer, or (2) where the customer's intent is to primarily offset part or all of the customer's own electrical requirements, but whose generating facility exceeds the 25 Kw maximum allowed under Net Metering Rate 58, defined herein as Partial Requirements Customer (qualifying facilities).

RATE:

Service provided to such customers by the Company shall be billed at the appropriate rate, by class of customers (i.e., residential, commercial, etc.) that is currently on file with the Commission. Customers under this rate schedule will not be net metered.

Minimum Bill: Basic Service Charge.

Rates may be updated annually, in correlation with the Company's annual Power Supply Cost Adjustment filing.

Partial Requirements Customer:

Basic Service Charge:*	
Single Phase:	$3.30 per month
Three Phase:	$9.34 per month
Energy Payment:	3.448¢ per Kwh Received

Parallel Generation Customer:

(1) For generating facilities rated at 100 Kw or Less

Basic Service Charge:*	
Single Phase:	$13.68 per month
Three Phase:	$17.25 per month
Energy Payment:	3.448¢ per Kwh Received
Capacity Payment:	$8.29 per Kw Received per month

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

State of Wyoming
Electric Rate Schedule

PARALLEL GENERATION
Rate 57

*The Basic Service Charge under this rate schedule is subject to the Reliability and Safey Infrastructure Rider Rate 55 (Sheet No. 60).

Capacity payments will be made only to those qualifying facilities that actually contribute to a capacity savings to the Company by a reduction in the demand charges paid by the Company to Black Hills Power, Inc. under the terms of the contract between the Company and Black Hills Power, Inc. regarding the determination of the billing demand. The kilowatts used for determining any capacity payment by the Company shall be the kilowatts supplied by the qualifying facility at the time of the Company's monthly system peak demand.

(2) For generating facilities rated at 101 Kw and Greater

The Company will enter into individual agreements.

GENERAL TERMS AND CONDITIONS:

1. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

2. The customer shall, with prior written consent of the Company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.

3. Any changes made to the customer's generating facility that increases the capacity, included in the customer's Interconnection Agreement, must first be approved by Montana-Dakota prior to installation to ensure the continued safe and reliable operation of the Company's electric system. If the Company is not contacted, the Company reserves the right to disconnect the facility until the issue is resolved.

4. The foregoing schedule is subject to Rate 59 and Rates 100 and 104. Any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 72

NET METERING SERVICE
Rate 58

AVAILABILITY:

Available to any customer that owns and operates a solar, wind, biomass or hydroelectric generating facility with a capacity of not more than 25 Kw that is located on the customer's premises and that is intended primarily to offset part or all of the customer's own electrical requirements. The generating facility must be interconnected and operated in parallel with the Company's existing transmission and distribution facilities. This service is offered in compliance with Wyoming Statutes §37-16-101 to 104.

APPLICABLITY:

Net Metering means measuring the difference between the electricity supplied by the Company and electricity generated by an eligible customer-generator and fed back to the electric grid over the applicable billing period.

RATE:

Basic Service Charge: The Basic Service Charge per the applicable standard service rate.

Energy Charge: If the energy supplied by the Company exceeds the customer generated energy, the energy charge (including the PSCA) per Kwh under the otherwise applicable standard service tariff shall be applied to the positive energy balance and charged to the customer.

If the energy supplied by the customer generator exceeds the amount of energy supplied by the Company, the net Kwh shall be credited to the customer's next monthly bill.

GENERAL TERMS AND CONDITIONS:

1. At the beginning of each calendar year, any Kwh credit balance accumulated during the previous year shall be purchased by the Company at the currently effective avoided cost rate (energy payment) applicable under Parallel Generation Rate 57.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 72.1

NET METERING SERVICE
Rate 58

2. The customer is responsible for all costs associated with its facility and is also responsible for all costs related to any modifications to the facility that may be required by the Company for purposes of safety and reliability.

3. A Net Metering facility shall meet all applicable safety and performance standards established by the National Electrical Code.

4. The customer is responsible, at their expense, for providing lockable switch equipment capable of isolating the net metering facility from the Company's system. Such equipment shall be approved by the Company and shall be accessible by the Company at all times.

5. A meter shall be installed between the parties to measure the flow of energy in each direction between the customer and Montana-Dakota. The customer shall be responsible for all expenses involved in purchasing and installing facilities necessary for the meter installation.

6. The customer shall enter into an Interconnection Agreement for Net Metering Service.

7. Any changes made to the customer's generating facility that increases the capacity, included in the customer's Interconnection Agreement, must first be approved by Montana-Dakota prior to installation to ensure the continued safe and reliable operation of the Company's electric system. If the Company is not contacted, the Company reserves the right to disconnect the facility until the issue is resolved.

    a. If the changes cause the generating facility's capacity to exceed the 25 Kw maximum allowed for under this rate schedule, the customer must enter into a new Interconnection Agreement under Parallel Generation Rate 57. Absent a new Interconnection Agreement, the Company reserves the right to disconnect the facility until the issue is resolved.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 72.2

NET METERING SERVICE
Rate 58

8. The foregoing schedule is subject to Rate 59 and Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 80

PARALLEL GENERATION GENERAL RULES
Rate 59

GENERAL RULES FOR PARALLEL GENERATION:

1. The interconnection between the utility and the qualifying facility will be limited to the service voltage and phases available at the qualifying facility. If different voltages or phases are required, the necessary changes will be provided by the qualifying facility.

2. The power factor and frequency of the qualifying facility shall be such as to not adversely affect the utility system. If corrective devices are required, they will be provided by the qualifying facility.

3. Fault protection equipment shall be provided by the qualifying facility. The utility and qualifying facility shall coordinate protective devices in order to limit damage to each system.

4. The qualifying facility's interconnection shall meet the requirements of local, state and federal codes.

5. The owner of the qualifying facility shall submit equipment specifications as requested by the utility prior to owner's installation of such equipment to assure compatibility and coordination with the utility system.

6. The owner of a qualifying facility will be requested to curtail, interrupt or reduce deliveries of electric energy, in order that the utility may construct, install, maintain, repair, replace, remove or inspect any of its equipment or any part of its system, or if it determines that curtailment, interruption or reduction of delivery is necessary because of safety, emergencies, forced outages or operating conditions on its system. Except in case of emergency, in order to minimize operating problems, the utility and qualifying facility shall give the other reasonable prior notice of any curtailment, interruption or reduction of delivery and its probable duration.

7. The Company reserves the right for periodic inspection of safety devices which are part of the interconnection. This would not affect the

responsibility of the qualifying facility to assure the operating safety of the equipment on its side of the interconnection point.

8. The Company reserves the right to disconnect any facility that has interconnected without utility authorization.

9. The Company has the right to disconnect and lock-out a qualifying facility's generating equipment with due notice whenever it has been determined that harmonics are being produced or other factors are present which would interfere with communications or otherwise cause degradation of service to other customers. If, in the judgment of the utility, an unsafe condition is created on the utility system by the operation of the qualifying facility, the utility shall have the right to disconnect the facility until the cause of such condition is eliminated.

10. In the event of a utility system outage or interruption of service, a qualifying facility's generator shall be capable of automatically disconnecting itself to prevent the utility's line from being energized. Also, a qualifying facility's system shall not be capable of energizing the utility's line when that line is deenergized.

11. A manually operated generator disconnect switch, provided by the owner of a qualifying facility, shall be accessible to utility personnel at all times. Such a switch would be used whether or not the owner is present to remove the qualifying facility's generator from the line in an emergency situation as determined by utility system conditions.

12. The owner of a qualifying facility shall maintain operating communications with the utility for facilities with a capacity of more than 100 Kw or as requested. Operating communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances and load reports.

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

State of Wyoming
Electric Rate Schedule

PARALLEL GENERATION GENERAL RULES
Rate 59

13. All necessary rights-of-way and easements to install, operate, maintain, replace and remove utility facilities, including adequate access rights, are to be furnished by the owner of the qualifying facility on owner's property.

14. The metering shall be adequate to measure energy, or energy and capacity, from the qualifying facility to the utility, from the utility to the qualifying facility, and, if necessary, adequate to determine the time at which energy is transferred from one party to another.

15. Interconnection costs shall be on an actual cost basis for all costs that are in excess of the costs that the utility would have incurred if it had not engaged in interconnected operations, but instead generated or purchased the same amount of energy or capacity. The owner of a qualifying facility is allowed up to one year to reimburse the utility for these costs.

16. Where no changes to the utility system are necessary except for installing additional metering, an average interconnection fee for qualifying facilities of 100 Kw or less shall apply.

17. The owner of a qualifying facility will indemnify and hold the utility harmless from all loss on account of injury, death or damage to property caused by the qualifying facility unless the injury, death or damage is the direct result of the negligence of the utility.

18. Qualifying facilities shall be required to execute a contract that specifies a one-year minimum term and describes the responsibilities, liabilities, ownership of equipment, and location.

19. The owner of a qualifying facility shall obtain and maintain general liability insurance in the amount of $500,000 for each occurrence or as determined by the Wyoming Public Service Commission.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 90

CONDITIONS OF SERVICE Rate 100

TABLE OF CONTENTS

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

State of Wyoming
Electric Rate Schedule

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

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

State of Wyoming
Electric Rate Schedule

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 generally 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 Regulatory Commissions as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. DEFINITIONS:

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

APPLICANT - A customer requesting Company to provide service.

COMMISSION AND COMMISSIONER - The Public Service Commission of Wyoming or a member thereof respectively.

COMPANY - Montana-Dakota Utilities Co.

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

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

DELIVERY POINT - The point where the Company's facilities join those of the customer.

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

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE - A customer desiring electric service must submit an application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. Any customer may be required to make a deposit as required by the Company in accordance with §V.4. The Company may refuse service or discontinue service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any customer who uses electric service 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 electric service until notified by the customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

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

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

4. RELOCATED FACILITIES – Where Company facilities are located on or adjacent to a customer's premises and where there is an encroachment(s) to electric facilities caused by the customer; said customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

5. NOTIFICATION OF UNSAFE CONDITIONS – The customer shall immediately notify the Company of any unsafe conditions associated with the Company's electric facilities at the customer's premises.

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

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

IV. LIABILITY:

1. CONTINUITY OF SERVICE – The Company's electric system is unusually widespread and has many interconnections with sources of power other than its own generating stations and it is subject to exposure by storms and other factors not under its control. The Company employs the latest developments in equipment and methods of operation for the purpose of maintaining adequate service. The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and

uninterrupted supply of electric service and will not be liable for any loss, injury, death or damage resulting from or caused by the interruption of the same.

2. CUSTOMER'S EQUIPMENT - Neither by inspection or rejection, nor in any other way does the Company give any warranty, expressed or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer, leased by the customer from third parties or used on the customer's premises. It is the obligation of the customer to consult with the Company regarding available maximum fault current and to provide such protection devices as may be necessary to safeguard the equipment and installation from interruptions, variation in voltage and frequency, single-phase energization of three-phase lines, reversal of phase rotation or other abnormal conditions. (Refer to Paragraph 710)

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 electricity or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

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

5. FORCE MAJEURE - In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of

any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or Company, acts of public enemies 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 electric lines, animal interference, sudden partial or sudden entire failure of electric transmission or supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required

for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

V. GENERAL TERMS AND CONDITIONS:

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

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

3. ELECTRIC SERVICE AVAILABILITY - Residential Electric Service is available to any residential customer for domestic purposes only. All normal sized equipment used for domestic lighting, heating, cooking and power, and used strictly for household purposes, may be supplied through one meter.

   a. Residential service is defined as service for domestic general household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments and mobile homes (this is not an all-inclusive list). In addition, auxiliary buildings on the same premises as the living quarters, used for residential purposes, may be served on the residential rate.

   Motors and other equipment which interfere with service to neighboring customers, all motors larger than 5 horsepower and

temporary or seasonal loads totaling more than 25 kilowatts (Kw) will not be permitted on the Residential Electric Service Rate without prior Company approval.

Only single phase service is available under the Residential Electric Service Rate.

b. Three phase service shall be served under the appropriate General Electric Service Rate.

c. General Electric Service is defined as service provided to nonresidential services, such as 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 parlors, 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).

d. If separate metering is not practical for premises that is using electricity for both residential purposes and for conducting business (or for nonresidential purposes), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or General) applicable to the type of service which constitutes more than 50% of the total connected load.

e. These rules will not change the classification of existing customers who were served electricity prior to October 1, 1988 except in the event of a different customer taking responsibility for the account.

f. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations

pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the appropriate General Electric Service Rate.

4. CUSTOMER DEPOSITS - The Company may require a deposit from an applicant for electric service (applicant) or an existing customer in accordance with Chapter 3, Section 7 of the Wyoming Public Service Commission's Rules:

The Company may require a deposit to guarantee payment for each service. This deposit shall not be considered as an advance payment of bills but shall be held as security for payment of service rendered. The Company may refuse service to an applicant or discontinue service to a customer for failure to comply with customer deposit requirements. The Company shall apply the policies governing customer deposits uniformly.

a. The Company may require a deposit if:

i. A prior service account with the Company remains unpaid and undisputed at the time of application for service;

ii. Service from the Company has been discontinued for:
A. Nonpayment of any undisputed delinquent bill;

B. Failure to reimburse the Company for damages due to the customer's negligent or intentional acts; or

C. Acquisition, diversion or use of service without the authorization of or knowledge by the Company;

iii. Information provided upon application for service is materially false or a misrepresentation;

iv. The application is for initial service with the Company or the applicant did not have service with the Company for a

period of at least 12 consecutive months during the past four years;

v. The applicant or non-residential customer is unable to pass an objective credit screen. In order to pass the objective credit screen, the applicant or non-residential customer must fulfill one or a combination of the following:

A. Received 12 consecutive months of service from the Company, with the undisputed portions of the 12 most recent bills paid in full when due;

B. Have a favorable credit rating with a third-party credit reporting agency; or

C. Receive a favorable credit rating from the Company's financial risk assessment tool.

vi. The request is for service at an address where a former customer with an undisputed delinquent bill for service still resides or conducts business;

vii. The applicant or the customer, has been brought within the jurisdiction of the bankruptcy court, or has had a receiver appointed in a state court proceeding, within the five-year period immediately preceding the request for service; or

viii. The Company has determined that it has a significant financial risk in continuing to provide service to a specific non-residential customer. The Company and the customer may attempt to reach a deposit agreement. If the Company and the customer are unable to reach an agreement, the Company shall file a confidential petition requesting expedited review and Commission approval prior to collecting the customer deposit. The petition shall contain the basis for the Company's determination, the amount of

deposit sought and sufficient information for the Commission to contact the customer.

b. The Company shall not require a deposit as a condition of new or continued utility service based upon any criterion not specifically authorized by the Wyoming Public Service Commission's Rules.

c. Unless otherwise ordered by the Commission, the required deposit shall not exceed the total amount of the customer's estimated bill for three months of highest use based on the premises' monthly bills during the immediate previous 12-month period. If billing information for the immediate previous 12-month period is not available, the deposit will be based on anticipated service characteristics and anticipated load.

d. The Company shall retain records showing:

   i. The name and address of each customer making the deposit;

   ii. The date and amount of the deposit; and

   iii. Each accounting transaction concerning the deposit.

e. The Company shall provide the customer a non-assignable receipt or other record of deposit, showing the date and amount received.

f. The Company shall calculate simple interest on deposits at the Commission Authorized Interest Rate described in Chapter 1, Section 3 (a)(xvii) of the Wyoming Public Service Commission's Rules. Interest shall apply only to deposits held for at least six months, but shall accrue from the initial date of deposit through the date the deposit is returned to the customer.

g. The Company may accept a written guarantee from an acceptable guarantor in lieu of a deposit to pay a customer's bill. After the Company has verified the customer's identity, the customer shall agree to permit the Company to provide the customer's account information to the guarantor upon the customer's default.

h. Deposits and any unpaid interest earned on deposits shall be applied as a credit to the customer's bill, unless requested by the customer to be refunded, when:

i. The accrued interest equals or exceeds $10.00. The Company shall apply the credit at least annually;

ii. A residential customer has received 12 consecutive months of service, with no cause to discontinue service; and the customer's bills have been paid when due;

iii. A commercial or industrial customer has received 12 consecutive months of service, with no cause to discontinued service; the customer's bills have been paid when due; and the customer passes the Company's objective credit screen; or

iv. Service is discontinued. The Company shall not require the customer to provide the original receipt in order for the deposit to be returned. Any credit balance on the account after the deposit is applied shall be refunded to the customer. If the Company is unable to make the refund due to lack of knowledge of the customer's location, additional interest will not accrue after the service discontinuation date. The Company shall manage such deposits as unclaimed property as required by Wyoming law (W.S. § 34-24-109).

5. METERING AND MEASUREMENT

a. Company will meter the electric service 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.

b. Meter Testing

1) Company's Testing - The Company's ongoing meter testing program is set forth in Rate 115.

2) Customer's Request - Upon request of the customer for a test of the accuracy of the Company's meter used on the customer's premises, the following provisions shall apply:

a. If the meter has not been tested within 12 months, the Company shall perform the test within a reasonable time without charge to the customer. The Company shall notify the customer of the time when the Company will conduct the test so the customer or the customer's representative may be present.

b. If the meter has been tested within 12 months, the Company shall notify the customer of the cost to perform the test. The Company shall notify the customer of the time when the Company will conduct the test.

c. The Company shall promptly advise the customer of the test results.

d. If a meter is found to be in non-compliance with the Company's approved meter testing program, the

Company shall refund the payment the customer advanced for the meter test and shall repair or replace the meter. The Company shall also adjust and refund to the customer the overpayment of preceding bills, in accordance with §V.6. No refund is required from the Company except to the customer last served by the meter prior to testing. If the Company has under collected, the customer shall pay the adjusted costs in accordance with §V.6.

e. The meter accuracy test charge amount is provided in §VI.1.f.

6. BILLING ADJUSTMENTS

a. In accordance with Wyo. Stat. § 37-2-218, if the Company charged, collected or received any rate or rates in excess of the rates fixed in the Company's tariff, the Company shall immediately refund to the customer the difference between the rates fixed in the tariff and the rates charged, collected or received. This shall also apply to meter errors described in §V. 5.

b. If the Company undercharged a customer as a result of a meter or metering inaccuracy or other continuing problem under the Company's control, the Company may bill the customer in accordance with Wyo. Stat. § 37-2-222, for the amount of unmetered electricity rendered in the 183 days immediately prior to the date the Company remedies the meter inaccuracy. The typical time period over which the undercharge may be collected shall be 12 consecutive months. The customer may elect to pay over a shorter period, or the Company may allow repayment over a longer period. This shall also apply to meter errors described in §V.5.

7. LATE PAYMENT - Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to the percentage set forth in §VI.2. will be applied to any past due balance, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

8. RETURNED CHECK CHARGE - A charge as set forth in §VI.1.b will be collected by the Company for any check not honored by the customer's financial institution for any reason.

9. MANUAL METER READING CHARGE: A charge as set forth in §VI.1.c 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 a minimum period of one year.

10. TAX CLAUSE
    a. In addition to the charges provided for in the electric 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:

        1. Any sales, use or excise taxes whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

        2. Any payment under any electric franchise ordinance amounting to more than 1% annually of the gross electric revenue derived by the Company from electric business within the corporate limits of the municipality, political subdivision, or other entity, imposing the payment.

3. The taxes imposed by the Sheridan Ordinance as adjusted for accounting and billing costs.

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

11. UTILITY CUSTOMER SERVICES:

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

1. Fire Call

2. Investigate hazardous condition on customer premises.

3. No lights or power investigation.

4. Maintenance or repair of the following Company-owned equipment on the customer's premises:
   i. Meter
   ii. Overhead Service Line
   iii. Underground Service Line

b. The following service calls will be performed at no charge during the Company's normal business hours of 8:00 a.m. – 5:00 p.m. Monday through Friday local time:

1. A reconnection of service to an existing facility (cut-ins) or a discontinuation of service

2. Checking Voltage or Loads

3. Locating Radio, CB or Television Interference

4. High Bill Complaint

To ensure the Company can service the call during normal business hours, the customer's call must be received by 12:00

p.m. local time on a regular work day for the disconnection or reconnection of service that same day.

12. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS - For service requested by customers after the Company's normal business hours defined in §V.11 and on Saturday, Sunday, or legal holidays, a charge will be made for labor at the overtime service rate set forth in §VI.1.g. plus the cost of any required materials.

    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.

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

14. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS - A fee, as set forth in §VI.1.e. will be collected for reconnecting electric service to any customer who has discontinued electric service at the same location during the preceding 12 month period, provided no other customer has taken service at the same location in the meantime.

15. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS - All amounts billed for service are due by the due date on the bill and will be considered delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company in accordance with Chapter 3, Section 9 of the Wyoming Public Service Commission's Rules.

a. Discontinuation Notice - The Company may discontinue service by reason of nonpayment after issuing a disconnect notice and upon not less than 7 days' notice of proposed termination for residential customers and not less than 3 days' notice for nonresidential customers. The disconnect notice will be mailed or delivered to the account holder or by telephone after customer verification and mailed to any third party previously designated by the account holder. Additional notice may be provided electronically. The notice shall contain:

1. The name of the person whose account is delinquent and the service address to be discontinued;

2. The amount of the delinquent bill;

3. The effective date of the notice and the date on or after which service is to be discontinued;

4. The Company's specific address and telephone number for information regarding how to avoid service discontinuation;

5. The names of agencies or organizations that have notified the Company that they render assistance to eligible persons who are unable to pay their utility bills; and

6. A statement advising the customer how to contact the Commission if discontinuation is disputed.

b. Landlord Account Holders - When the Company is discontinuing service for nonpayment by a landlord, the Company shall post, mail, or deliver to each known tenant a written notice, excluding the dollar amount, informing the tenant only of the impending disconnection and advising each tenant it has 15 days to arrange directly for service, as permitted by the available facilities. The tenant shall not be held responsible for the landlord's delinquent utility billings. The Company will post the

notice at a central location on or in the rental building if all tenants cannot be identified.

c. The Company will notify the customer that, if prior to the initial date for the discontinuation of service, the customer provides the Company with written verification from a health care provider responsible for the care of customer or his/her co-habitants stating that their health or safety would be seriously endangered if service were discontinued, the Company shall extend the date for discontinuation set forth in the notice by 15 days (22 days total) to allow for bill payment.

d. The Company shall attempt to make actual contact with the customer either in person or by telephone, after the customer identity verification, before discontinuing service during the cold weather period of November 1 through April 30.

e. The Company shall also provide notice of discontinuation or account delinquency to a third party if the customer, or person acting for the customer, has requested the Company do so after the customer identity verification. The Company shall advise the Customer that the right to request third-party notification does not create third-party liability for payment.

f. If the customer defaults, the Company shall provide the discontinuation notice to any guarantor and the customer simultaneously. The guarantor's service shall not be subject to discontinuation as a result of the customer's default.

g. The Company shall remove a guarantor when:

1. The customer has received 12 consecutive months of service with no cause for discontinuation, bills have been paid when due and the customer passes an objective credit screen

2. The guarantor has paid all amounts due for service through the date the Company received the request to terminate the guarantor agreement; or

3. An additional agreement with the Company is in place.

h. Reconnection After Nonpayment - To have service restored after discontinuation of service for nonpayment, a residential or a non-residential customer must first pay a charge for reconnection as set forth in §VI.1.d, and must also pay the delinquent balance in full or execute a written deferred payment agreement, if eligible. The Company may also require a deposit to secure payment of future electric bills. See §V.4 Customer Deposits.

i. Discontinuation - The Company may discontinue service between 8:00 a.m. to 4:00 p.m., Monday through Thursday if not a legal holiday or the day preceding a legal holiday without further notice when:

1. The notification period has elapsed and the delinquent account has not been paid; or

2. Acceptable payment arrangements have not been made with the Company.

j. Service Extender – Service Extender provides a temporary alternative to discontinuing electric service for non-payment by extending a controlled level of service to the delinquent customer prior to service being discontinued. The minimum size Service Extender used for a Residential customer is 10 amps. Service Extenders shall not be applicable to a residence where the primary source of heating is electricity. If the Company choses to install a Service Extender, service may be

discontinued without further notification. Notification of the Service Extender shall be delivered to an adult or posted at the affected premises and shall include:

1. The customer's name;

2. Date the Service Extender was installed;

3. Customer operational instructions for the Service Extender;

4. Telephone number and address of the Company; and

5. Warning that service may be discontinued without further notification.

k. The Company shall assist persons who are unable to pay their electric service bills with determining available government assistance.

16. PROHIBITIONS AGAINST SERVICE DISCONTINUATION – The Company shall not terminate service for bill nonpayment under the following conditions:

a. On a legal holiday as defined by Wyoming Statute §8-4-101, or the day before such a legal holiday;

b. During the period from December 24 through January 2, inclusive;

c. On any day in which the Company cannot reconnect service;

d. If the customer enters into an arrangement with the Company for payment of the delinquent billing over a reasonable time and the customer complies with payment arrangements;

e. If there are monies owed due to meter or other billing error, and the customer complies with payment arrangements;

f. At a previous address for a different class of service;

g. For nonutility services or appliance or merchandise provided by, or sold by, the Company to the customer;

h. If the customer is paying the electric service bills on time, even though a prior customer with an undisputed delinquent bill for service resides or conducts business at the same address;

i. If an electric service bill, or part of a bill, is legitimately in dispute, and if the customer duly pays the electric service bill, or bill portion, not in dispute;

j. If the temperature for the community closest to the customer's location is forecasted by the National Weather Service or other reputable source to be below 32°F in the impending 48 hours, or if conditions are otherwise especially dangerous to health, and the customer is:

1. A residential customer;

2. A non-residential customer providing service essential for the protection of public health, safety, or welfare; and:

3. Unable to pay for service in accordance with the Company's billing requirements and is actively seeking government assistance or has exhausted such assistance; or

4. Able to pay for service in installments; or

k. If the customer pays a bill on time for a specific service at a specific location, even though the customer is receiving another service that is subject to discontinuation for bill nonpayment.

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

17. 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. For the use of electricity for any property or purpose other than that described in the application made for service.

    b. For failure to maintain in good order service entrance facilities or equipment owned by the customer.

    c. For use of equipment which adversely affects the Company's service to its other customers.

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

    e. The Company may discontinue service for causes other than non-payment after issuing a disconnect notice in accordance with §V.15.a. The discontinuance of service for causes other than non-payment shall occur on the days and during the hours stated in §V.15.i.

    f. 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.

    g. The Company may discontinue service without advance notice for reasons of safety, health, cooperation with civil authorities, fraudulent use, tampering with or destroying Company facilities.

    h. The Company may collect a reconnect fee as prescribed in §VI.1.d. before restoring electric service which has been discontinued for the above causes.

18. 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 Montana-Dakota Utilities Co. The bill shall be computed at the applicable rate, and the amount reduced by 33 1/3%.

19. REFUSAL TO SERVE NEW CUSTOMERS OR EXPAND EXISTING SERVICE – A utility may refuse to provide, expand or materially change service to a requesting customer when:

    a. The Company does not have adequate facilities to render the service requested and the customer is not willing to comply with the utility's line extension policy;

    b. The requested service appears to be unsafe or likely to adversely affect service to another customer; or

    c. The requesting customer is indebted to the Company for service previously rendered and satisfactory payment arrangements have not been made with the utility.

        1. If indebtedness for service rendered at a former location is in dispute, the requesting customer shall be provided service at the new location upon complying with the Company's deposit requirements and paying the amount in dispute. Upon settlement of the disputed amount, any balance due the customer shall be refunded with accrued interest at the Commission Authorized Interest Rate described in Chapter 1, Section 3(a)(xvii) of the Wyoming Public Service Commission Rules.

        2. The Company shall not refuse service to a new customer because of debts of a previous customer at the same location.

        3. The Company may refuse service due to unpaid line extension charges for facilities serving the location.

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

VI. MISCELLANEOUS CHARGES

		Amount or Reference
1.	Service Charges	
a.	Consumer deposits	Rate 100 §V.4.
b.	Returned check	$30.00
c.	Manual Meter Reading Charge	$26.05
d.	Minimum reconnect charge after discontinuation of service for nonpayment or other causes	
	- During normal business hours	$35.00
	- Removal of service extender	$35.00
	- After normal business hours	Minimum of $140.00
e.	Minimum reconnect charge applicable to seasonal or temporary customers	
	- During normal business hours	
	- Customers with non-demand meters	$35.00
	- Customers with demand meters	$70.00
	- After normal business hours	Minimum of $140.00
f.	Special test of meter at customer's request (see Rate 100 §V.5.b.2 as to when this charge is applicable)	
	- Meter error more than ±2%	None
	- Meter error within ±2% and meter was tested within the prior 12 months	Labor & materials Minimum of $40.00
g.	Service request after normal business hours	Materials & labor Minimum of $140.00

h. Electric extension policy — Rate 104

		Per Month	Approx. Annual Percent
2.	Late Payment Charges (on unpaid balance)	1%	12%

SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:

Rate 104 - Electric Extension Policy
Rate 105 - Dark Sky Lighting Service
Rate 122 - AutoPay Plan
Rate 123 - Summary Billing Plan
Rate 125 - Balanced Billing Plan

VII. ELECTRIC SERVICE RULES:

Section 100 – GENERAL

101. Electrical Codes and Ordinances

The Electric Service Rules and Regulations contained herein are supplementary to and do not intentionally conflict with nor supersede the latest edition of the National Electrical Code, the National Electrical Safety Code, nor such state and municipal laws and ordinances that may be in effect in the areas in which the Company furnishes electric service, except that where the requirements of these Electric Service Rules and Regulations exceed those of such codes, laws, and ordinances, these Electric Service Rules and Regulations shall apply. Existing installations, including maintenance replacements, that currently comply with prior revisions of these rules and regulations, need not be modified to comply with these rules except as may be required for safety reasons.

102. Wiring Adequacy

Wiring codes provide minimum requirements for safety. Installation of wiring capacity greater than minimum code requirements is recommended to bring to the customer all the benefits of electric service and to protect building investment by minimizing obsolescence resulting from an inadequate wiring system.

103. Inspection of Wiring
Where permits and inspections covering customer's wiring and installation are required by local ordinance, it is mandatory that such requirements be fulfilled before the Company will make connections to the customer's installation. In locations where such inspections are not required by law or ordinance, an affidavit by the wiring contractor stating that the wiring has been done in compliance with the National Electrical Code will be acceptable.

104. Permits, Certificates, Affidavits
It is the responsibility of the customer to obtain all necessary permits, certificates of inspection or affidavits as required in Paragraph 103 above and to notify the Company promptly of any proposed alterations or additions to customer's load. Failure to comply with these requirements may result in delayed connection, interruption of service or damage to apparatus.

105. Consultation with the Company
105.1 The location, size and character of the customer's load and the current, voltage, frequency, phases, etc. which the Company has available at the customer's location will determine the type of service supplied to the customer.

105.2 Architects, engineers, contractors, electric dealers, wiremen and others must confer with local representatives of the Company to determine the type of service that will be available before designing or preparing specifications for new electrical installations or alterations to existing installations.

105.3 In all cases involving large installations and other cases where any doubt exists, full information as to the type of service available should be obtained from the Company.

106. Unauthorized Use of Service
106.1 Unauthorized use of service is defined as any deliberate interference that results in a loss of revenue to the Company. Violators are subject to prosecution.

106.2 Types of unauthorized use of service include, but are not limited to, the following:

(a) Bypass around meter.
(b) Meter reversed.

(c) Equipment connected ahead of meter.
(d) Tampering with meter that affects the accurate registration of electric usage.
(e) Electricity being used after service has been discontinued by the Company.

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

(a) All costs associated with investigation or surveillance;
(b) Estimated charge for non-metered electricity;
(c) All time to correct situation;
(d) Any damage to Company property.

106.4 A customer's service disconnected for unauthorized use of service shall be reconnected after the customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid any 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 equipment, costs incurred in the preparation of the bill, plus costs as outlined in Paragraph 106.3;
(d) Applicable reconnection fee;
(e) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with §V.4 and Chapter 3, Section 7 of the Wyoming Public Service Commission's Rules.

107. Unauthorized Attachments to Poles

107.1 The unauthorized attachment of any flags, banners, signs, clothes lines, antennas, etc. to Company poles is prohibited. The use of poles for placards or other advertising matter is forbidden. The Company will remove such unauthorized attachments without notice and may prosecute any such trespassers.

107.2 Customers are cautioned to locate antennas so that they are beyond falling distance from the Company's lines, either transmission or distribution. Antennas and lead-ins shall be located a safe distance from and shall never cross over or under the Company's lines or contact the Company's poles. The Company disclaims all responsibility where such equipment contacts the Company's lines, poles or equipment.

Section 200 - USE OF ELECTRIC SERVICE

201. Rate Schedules
Electric service will be billed under the rate schedule that applies to the class of service used. Rate schedules applicable to various classes of service may be obtained from the Company upon request.

202. Resale of Energy
The Company will not supply energy for resale except as expressly covered by special contract or where such provision is a part of the rate schedule.

203. Temporary Service
Temporary service is any service for construction work, carnivals, gravel pits, occasional lighting, etc., which is not expected to continue in use for a period long enough to justify the construction cost necessary for extending service. When temporary service is desired the customer shall, in addition to paying the scheduled rates, make deposit in advance in the amount of the Company's estimated cost of installing and furnishing such temporary service facilities together with the cost of disconnecting and removing same and the estimated billing to the customer for electric service. Final billing will reflect credit for the salvage value of materials used in providing the temporary service. Any deficiency in such advance payment shall be paid by the customer upon presentation of a bill by the Company. Any amount deposited in excess of final billing by the Company will be refunded to the customer.

204. Standby Service
Where electric service is supplied as standby to a customer's generating facilities or vice versa, the customer shall provide and install at the customer’s expense a suitable double-throw switch or other device which will completely isolate the customer's power facilities from the Company's system. The service entrance shall be installed so that the

phase conductors will be totally isolated from the customer's wiring before the standby unit is put into operation.

205. Parallel Service
Parallel operation of the customer's generating equipment with the Company's system shall be permitted to the extent provided in other approved rates.

206. Transformer Installations on Customer's Premises
206.1 The Company will supply transformers to be installed on the customer's premises when requested by the customer and in accordance with the following paragraphs.

206.2 The customer shall agree to indemnify and save the Company harmless, except for willful default or neglect on the Company's part, from any loss, damage, expense or liability, incurred or arising from, or out of the installation, operation, maintenance, repair or removal of its transformers, cables, conductors, apparatus and all other Company property, material or equipment placed on the customer's premises.

206.3 Company's power or distribution transformers will not be installed in the customer's building.

206.4 The Company will furnish, own and maintain conventional oil filled transformers at no cost to the customer. However, where dry type transformers, transformers containing a nonflammable insulating coolant or oil filled transformers of special voltage or design are required they shall be owned, installed and maintained by the customer at the customer's expense.

206.5 Padmount transformers may be installed on customer's premises. The customer shall furnish a suitable concrete pad, conduit, ground rod and service conductors as noted in Figure 5. Where the customer has more than four parallel conductors, a cable junction enclosure and conduits to the transformer location may be required. The customer shall consult with the Company to determine when a cable junction enclosure is required.

206.6 Where the transformer is installed adjacent to an asphalt or concrete driveway, parking lot, or walkway, the customer shall provide conduit from the transformer location to a point beyond the driveway, parking lot, or walkway to accommodate the Company's

primary voltage cable. The customer shall provide barriers and clear zones to protect transformer from damage and to allow proper cooling and access to conductor compartments. The customer shall consult with the Company to determine the proper size conduit and protective barriers.

206.7 Refer to Figure 5 for additional information on transformer location.

Section 300 - ELECTRIC SERVICE AVAILABLE

301. Frequency

All service supplied by the Company is alternating current at a nominal frequency of 60 Hertz.

302. Secondary Voltages (See also Section 400.)

302.1 In general, the following classes of service are normally supplied:

Phase	Wires	Nominal Voltage	Nominal Service	
	1	3	120/240	Single Phase Lighting & Power
	3	4 Delta	120/240	Combined Light & Power*
	3	4 Wye	208 Grd Y/120	Combined Light & Power
	3	4 Wye	480 Grd Y/277	Combined Light & Power**
	3	4 Delta	240/480	Combined Light & Power*

*Overhead Primary
**Underground Primary

Note: The Company follows the provisions of ANSI C84.1; latest revision, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

302.2 Only one class of service voltage is provided to a single customer location.

302.3 Service at other voltages may be made available for approved loads upon special application to the Company. Supplying such service may require special construction and equipment by the customer and the Company. The details of such construction and equipment are subject to negotiation between the Company and the customer before service is supplied.

302.4 As the voltage and number of phases which will be supplied depend upon the character of the load, its size, and location, it is necessary that the customer consult with the Company regarding the type of service which will be furnished before proceeding with the purchase of equipment or the installation of wiring. (Refer to Paragraph 105)

302.5 The customer's wiring for single phase installations shall be such that the difference in loads on each side of the supply neutral shall not exceed 10% of the total load.

302.6 For three phase grounded wye installations, the load shall be balanced so that the difference in loads on the separate phases shall not exceed 10% of the total load.

303. Primary Voltages (See also Section 500.)
Service may be made available at primary voltage of 2400 volts or higher. The available primary voltage is dependent upon the local primary voltage.

Section 400 - SECONDARY VOLTAGE SERVICE
(Under 600 Volts)

401. Secondary Voltage Service Connections
The location of the service connection is subject to approval by the Company. The Company will cooperate with the customer to the fullest extent practicable in determining such location. Once established, any change by the customer may result in billing to the customer for any additional work or materials required by the Company.

402. Service Connections and Disconnections
All connections or disconnections of overhead or underground services, regardless of the voltage, will be made by the Company at the point where the Company's facilities join those of the customer. No customer or agent of the customer will be authorized to make such connections or disconnections. (Refer to § III.1. and Paragraphs 103 and 104)

403. Number of Service Drops
In general, one service drop will be installed for each customer location. Exceptions will be made in special cases where it is mutually advantageous to the customer and the Company.

404. Services in Raceways
Where services are installed in raceways, the installations must comply with the requirements of the latest edition of the National Electrical Code. In addition, effective with services installed on and after April 25, 2006 metered conductors shall not be installed in the same raceway as unmetered service conductors.

405. Service Entrance Requirements
405.1 The Company recommends that the service entrance for single family residences be not less than 100 ampere. The service entrance shall be sized and installed in accordance with provisions of the National Electrical Code, state code, and local ordinances. Bare neutral wire shall not be installed in metallic conduit due to the possibility of radio interference.

405.2 Ample length of service entrance conductor shall be left protruding from the service head and at padmount equipment facilities to allow for proper connection to the service drop for overhead installations and to padmount equipment terminals.

405.3 When entrances are parallel in two or more conduits, all phases shall be run in each conduit and all wires shall be of the same length.

406. Identification of Conductors
406.1 For purposes of identification, the neutral wire of each single phase entrance shall be clearly marked at the service outlet as well as at the meter location.

406.2 Where 4-wire, three phase service entrances are installed, the neutral conductor and the "wild" phase conductor (nominal 208 volts to ground) shall each be clearly marked at the service outlet, at the meter and at service equipment.

407. Overhead Service Drops
407.1 The service entrance shall preferably be through the eave and be located so the overhead service drop will be as short as practical and maintain all clearance requirements. (Refer to Figure 1 and Paragraph 407.4)

407.2 In cases where proper clearances cannot be maintained by attaching the service drop directly to the building, the customer shall install and maintain a supporting

structure of sufficient mechanical strength to support the wires and of sufficient height to provide the necessary clearances.

407.3 The customer shall furnish and install the necessary facilities for firmly mounting a Company supplied service drop attachment.

407.4 Service drop conductors shall not be readily accessible and when not in excess of 750 volts, shall conform to the following general requirements (Refer to the National Electrical Safety Code for possible exceptions) :

Clearance over roof – Multiplex service drop conductors shall have the following minimum clearance over a roof:

10.0 feet - from the highest point of roofs or balconies over which they pass with the following exceptions:

Exception 1: The clearance shall be maintained at not less than 3.0 feet above roof or balcony not readily accessible.

Exception 2: Where a roof or a balcony is not readily accessible, and a service drop passes over a roof to terminate as a (through-the-roof) raceway or approved support located not more than 4.0 feet, measured horizontally from the edge of the roof, the clearance above the roof shall be maintained at not less than 1.5 feet for a horizontal distance of 6.0 feet from the raceway or support, and shall be maintained at not less than 3.0 feet for the remainder of the horizontal distance that the cable or conductor passes over the roof.

Note: A roof or balcony is considered readily accessible to a person, on foot, who neither exerts extraordinary physical effort nor employs special tools or devices to gain entry.

Clearance from ground – Multiplex service drop conductors shall have the following minimum clearance from ground:

18.0 feet - over roads, streets and other areas subject to truck traffic. Trucks are defined as any vehicle exceeding 8 feet in height.

18.0 feet - over driveways, parking lots and alleys. This clearance may be reduced to the following values:
(1) 17 feet – where multiplex service drops cross over or run along alleys, driveways, or parking lots.
(2) If the height of attachment to a building or other installations does not permit these requirements:
(a) 14 feet – over residential driveways for multiplex service drops limited to 150 volts to ground.
(b) 10 feet – over residential driveways for drip loops of service drops limited to 150 volts to ground.

14.0 feet - over spaces or ways accessible to pedestrians or restricted traffic only. This clearance may be reduced to the following values:
(1) If the height of attachment to a building or other installations does not permit these requirements:
(a) 12 feet - for multiplex service drops limited to 150 volts to ground.
(b) 10 feet - for drip loops of service drops limited to 150 volts to ground.

24.5 feet - over swimming pools, or within 10 feet, measured horizontally, of the pool edge. In addition, there must be 16.5 feet clearance measured in any direction from every point on a diving platform or tower.

The vertical clearance is derived using the latest edition of the National Electrical Safety Code rule and, where necessary, adding 2 feet for vertical movement safety factor adopted by Company.

408. Secondary Voltage Underground Service

408.1 Where the customer desires an underground service, the customer must furnish and install conduit from the line side of the meter socket to a point a minimum of 18

inches below grade. (Refer to Figure 1.) The customer shall also provide necessary conduit for services under any asphalt or concrete drive-way, walkway, parking lot, or other areas where it is impractical to excavate.

408.2 If a customer requests to convert from an overhead service to an underground service, the customer must provide all necessary changes to the service entrance, including relocation, and the conduit described in 408.1 above. The customer must also provide a Company approved trench ready to accept the underground service conductors including back filling, surface restoration and any future settlement or erosion. If the customer requests the Company to provide this work, the Company will charge the customer for this service. In addition, if the service length is less than 150 feet, a fee equal to the Company's labor and equipment costs to convert the average 100 feet service line will be charged. If the service length is greater than 150 feet the customer will pay a fee equivalent to the Company's actual labor and equipment costs for the conversion.

409. Mobile Home Service

The customer shall install and maintain the metering pedestal or meter socket and meter mounting device. The customer, as the term is used in this section, is considered to be the mobile home court owner for installations in mobile home courts and the mobile home owner for installations on a private lot.

Section 500 - PRIMARY VOLTAGE SERVICE
(2400 Volts or More)

501. General

The Company offers electric service at primary voltages of 2400 volts or higher. A customer desiring to take service at primary voltage shall furnish and own all electrical equipment from the point of delivery and shall consult the Company to assist in determining the size, type and arrangement of service entrance equipment and conductor specifications required for the customer's particular needs.

502. Service Entrance Equipment

The service entrance equipment shall perform the following functions:

a. Isolate the load from the supply circuit by visible means.
b. Automatically break the circuit in the event of overload.
c. Permit manual opening of the circuit at full load.

503. Overcurrent Protection

The need for overcurrent protective coordination requires consultation with the Company. Overcurrent protective devices may be as follows:

a. Fuses
b. Automatic trip circuit breakers

The overcurrent protective device must have an interrupting rating, at circuit voltage, equal to or exceeding the maximum short circuit current available at the location where service is taken.

504. Disconnecting Means

504.1 The disconnect switch shall provide visible evidence that the circuit to which it is applied is open or disconnected. It shall be located on the supply side of the circuit.

504.2 Where fuses are used, the disconnect switch shall be a gang operated load break switch.

504.3 Where automatic circuit breakers are used as circuit protective equipment, the disconnect switch can be non-load break.

505. Load Balance

Loads on the three phases shall be balanced as closely as possible. The maximum unbalance permitted between individual phase loads is 10% of the total three phase load.

Section 600 - METERING

601. General

The Company will install the necessary meters to measure the electrical energy delivered under each account for a particular class of service. The Company shall install and maintain at its own expense all equipment necessary to regulate and measure the commodity delivered per tariff.

601.1 Meter Reading and Billing

a. Each service meter shall clearly indicate the units of measurement. If the utility bills customers in a different unit of measurement than the service

meter indicates, the conversion factor shall be stated on the customer bill. In cases where special types of meters are used or where the readings of a meter must be multiplied by a constant to obtain the units consumed, that information shall be placed on the customer bill.

b. Bills shall be rendered periodically and shall show the meter readings at the beginning and end of the billing period, the date of the meter readings, the units consumed, the class of service and other information necessary to enable the customer to readily re-compute the amount of the bill. Each bill shall bear upon its face the date of the bill and the latest date it may be paid without penalty. Estimated meter readings or budget billing shall be clearly identified on the bill. Electric meters shall be read monthly as nearly as possible on the same day within the billing cycle.

602. Meter Installations

602.1 The Company will furnish all meters required for billing purposes. It shall be the customer's responsibility to furnish, install and maintain the meter mounting device. Company approved specifications for electric meter sockets and metering transformer enclosures are listed below:

Self-Contained Meter Sockets - Single Phase, Three Phase and Multiple Position Type

1. The customer will utilize meter sockets from a Company approved list of manufacturer and models as posted on the company's website.
2. U.L. approved, ringless style.
3. 100 ampere minimum for overhead service installations. 200 ampere minimum for underground service installations.
4. Stud connectors are required for all socket rated 320 amps of greater.
5. For sockets rated below 230 amps, stud connectors are recommended. Only Company specified meter sockets are approved with lay-in connectors.
6. Equipped with a fifth terminal in the nine o'clock position where network metering is required.
7. A lever by-pass feature is required for all commercial and industrial installations. Upon review by Company, an exemption may be provided.

8. A lever by-pass feature is recommended for all residential installations.

Metering Transformer Rated Meter Socket

1. U.L. approved, ringless style with a one piece cover.
2. Minimum size must provide space for test switch installation.
3. Socket must have six terminals for single phase and 13 terminals for all other configurations.
4. Automatic by-pass feature is not acceptable.
5. The customer will utilize instrument rated meter sockets from a Company approved list of manufacturer and models.

Metering Transformer Enclosure (Secondary Service)

1. Recommend a durable, weather-resistant finish and weather-proof seal.
2. Must be provided with hinge-type cover and provisions to attach locking or sealing device.
3. Minimum size 10" x 24" x 30" with suitable mounting brackets for current and voltage transformers.
4. Consult with Company prior to purchasing any metering transformer enclosure.

602.2 Self-contained rate meter sockets shall be placed outdoors.

602.3 On instrument rated meter sockets, the Company will furnish and install the metering transformers. Such meter sockets shall be arranged for outdoor metering. (Refer to Figures 2 and 3)

602.4 Where a secondary metering transformer enclosure is required, the customer shall furnish and install an enclosure. Such enclosures shall contain only the service entrance conductors and metering transformers. The metering transformers shall be installed on the line side of the customer's disconnecting device. Suitable lugs, connectors, etc. for connecting metering transformers to service mains shall be provided by the customer. (Refer to Paragraph 602.1)

602.5 For installations having switchboards, the metering transformers may be mounted in the switchboard bus, provided they are accessible for changing and testing. Metering transformers shall be mounted on the source side of the main switch.

602.6 Meters and test switches may be mounted on a suitable unhinged panel adjacent to the metering transformer enclosure.

602.7 No device other than a Company-owned or Company-approved device shall be placed into or ahead of the meter socket.

603. Meter-Switch-Fuse Wiring Sequence

For all secondary voltage metering installations, the meter entrance switch and main line fuse or breaker shall be installed in the order named with respect to power flow. All circuits downstream from the meter shall have proper overcurrent protection devices. Additionally, for 480 volt installations, a customer-owned main service switch shall be installed on the source side of all 480 volt, self-contained meters. This switch shall be located no closer than three feet either left or right of the meter socket, and the switch cover is sealed by the Company. The switch shall be labeled “Utility Disconnect”. By exception and upon consultation with the Company, an overcurrent circuit breaker may be installed ahead of a gang style metering installation with 6 or more sockets as an Emergency Disconnect. Access to the Emergency Disconnect Switch shall be lockable and shall be locked by the Company.

604. Meter Locations

604.1 Each meter shall be located outdoors in a place of convenient access where it will not create a hazard. The location shall be agreed upon by the customer's representative and the Company and in compliance with Chapter 3, Section 16 of the Wyoming Public Service Commission’s Rules. (Refer to Figure 1)

604.2 Meters shall be located so that there is not less than 3 feet of unobstructed space, from the ground up, in front of the meter so that the center line of the meter is not less than 4 feet nor more than 5 feet above the floor, ground, or permanent platform from which the reading will be taken. On group installations, the minimum height is 2 feet – 6 inches and the maximum is 6 feet. The minimum center spacing between meter sockets shall be 7 ½ inches horizontally and 8 ½ inches vertically.

604.3 Meter Sockets shall be permanently mounted on secure structures such as houses, buildings, poles, etc. All required conduit will be provided by the customer. (Refer to Figures 1, 2 and 3)

604.4 Enclosures shall not be placed over the meter socket unless approved by the Company.

605. Indoor Metering

Meters shall be located outdoors as noted in Paragraph 604.1. However, depending on the circumstance and after consulting with the Company, locating the meters indoors may be approved on a case by case basis. Where approved, indoor meters for multiple dwellings, large office buildings, etc. shall be grouped and located as near the service entrance location as practicable. In the event such location renders the automatic meter reading equipment ineffective customer will be responsible for costs associated with remedying the situation.

606. Wiring Diagrams

Typical wiring diagrams for various types of self-contained meters are shown on Figure 4. These are subject to change from time to time with advancement in available metering equipment.

607. Labeling

Where two or more meter mounting devices are installed at one location, each shall be labeled so that it may be identified as to the customer served. Electrical contractors are requested and cautioned to check and identify wiring circuits carefully to avoid metering errors due to incorrect circuitry. Permanent (mechanically fastened) engraved plates shall be placed on the exterior of the meter base on a non-removable panel.

608. Seals

All meters and all points of access to customer wiring on the source side of the meter will be sealed by the Company. All cabinets and switch boxes, either inside or outside of the building, which contain unmetered wires shall have provisions made for sealing before service will be supplied.

Section 700 - UTILIZATION EQUIPMENT

701. Interfering Loads

Whenever a customer's utilization equipment has characteristics which cause undue interference with the Company's service to other customers, the customer shall provide, at the customer's expense, the necessary equipment to prevent or eliminate such interference. The Company may install and maintain at the customer's expense and upon approval of the customer the necessary equipment to eliminate such interference if it deems it advisable. When a customer's equipment or method of operation causes such interference and the customer does not correct the condition after being so requested by the Company, the Company reserves the right to discontinue the electric service, following written notification of its intent to do so; and service will not be re-established until the conditions complained of have been corrected.

702. Voltage Flicker and Harmonics

702.1 The Company uses the latest revision of the IEEE Standard 141 as the guideline for the maximum allowable voltage flicker that can be caused by a customer's load as measured at the point of metering. This guideline refers to the momentary dip in voltage that may result from the customer's operation of switches, starting of motors, etc.

702.2 Customer's electric load shall comply with the recommendations within Section 10 of the latest revision of the IEEE Standard 519 "Recommended Practices & Requirements for Harmonic Control in Electric Power Systems" at the point of metering connection. The IEEE Standard is available for review by the customer by contacting the Company to discuss by phone or to arrange an appointment at the Company's Sheridan office.

703. Power Factor

Whenever the customer's utilization equipment is of such characteristics as to produce a low power factor, the Company reserves the right to require the customer to raise such power factor, at the customer's expense, or to pay additional charges as provided in certain of the Company's rates on file with the Regulatory Commission of the state wherein the customer is located.

704. X-Ray Equipment

At the option of the Company, x-ray equipment may be separately metered and/or supplied from separate transformers.

705. Electric Welders

Electric welding apparatus shall require special arrangements with the Company to determine its ability to serve before installation is made. (Refer to Paragraph 703)

706. Electric Motors

706.1 Motors are normally designed to operate at their rated voltage, plus or minus 10%; thus a 220 volt motor should operate satisfactorily at 208 volts or 240 volts.

706.2 To assure adequate safety to personnel and equipment, the customer shall provide and maintain protective devices in each phase to protect all motors against overloading, short circuits, ground faults and low voltage, and to protect all three-phase motors against single-phasing and phase reversal.

706.3 Motors for use at 120 volts single-phase are limited to locked rotor currents of 25 amperes if started more than 4 times per hour, and 50 amperes if started less frequently.

Motors for use at 208 or 240 volts single-phase will generally be limited to 3 h.p. and a maximum of 4 starts per hour. The Company must be consulted for single-phase motors above 3 h.p. Compensating starting equipment may be required to limit the starting current and when required, shall be furnished by the customer. (Refer to Paragraph 702)

706.4 The size of the three-phase motors permitted will depend upon the effect starting the motor has upon the customer's system and the Company's other customers in the area. This effect will depend upon the magnitude of the starting current and the frequency of starting. (Refer to Paragraph 702)

When necessary, the customer will be required to reduce the amount of starting current to an acceptable level by installing suitable motor-starting equipment or by using motors designed for smaller starting currents.

706.5 When more than one motor can start simultaneously, the sum of the maximum starting currents of those motors starting simultaneously and also the sum of their horsepower rating shall be furnished to the Company to determine when reduced voltage starting may be required.

707. Flashing Display Signs
The Company reserves the right to refuse service for "flashing" display signs or display lighting where such service would interfere with voltage regulation of the secondary system.

708. Fluorescent and Gaseous Tube Lighting
High power factor ballasts or transformers must be used for fluorescent, sodium vapor, neon or other gaseous tube lighting equipment. It is required that such equipment operate at a power factor of not less than 90% lagging.

709. Electric Heat Equipment
A customer planning to install resistance type heating, heat pump, electric furnace, electrode boiler, etc. shall consult with the Company, before purchasing the equipment, so that operational modes of this equipment are determined to be acceptable for connection to the Company's distribution system. It is important that consultation is obtained prior to installation of this equipment so the Company can provide adequate capacity to efficiently serve the customer's requirements.

710. Computers and Electronic Equipment
Computers and other sensitive electronic equipment which require high grade, uninterrupted power may, on occasion, experience problems when connected directly to the Company's distribution system. The customer should contact their equipment supplier or consultant to ascertain the need for lightning arresters, surge suppressors, isolation transformers, and standby or uninterruptible power supplies. (Refer to § IV.2.)

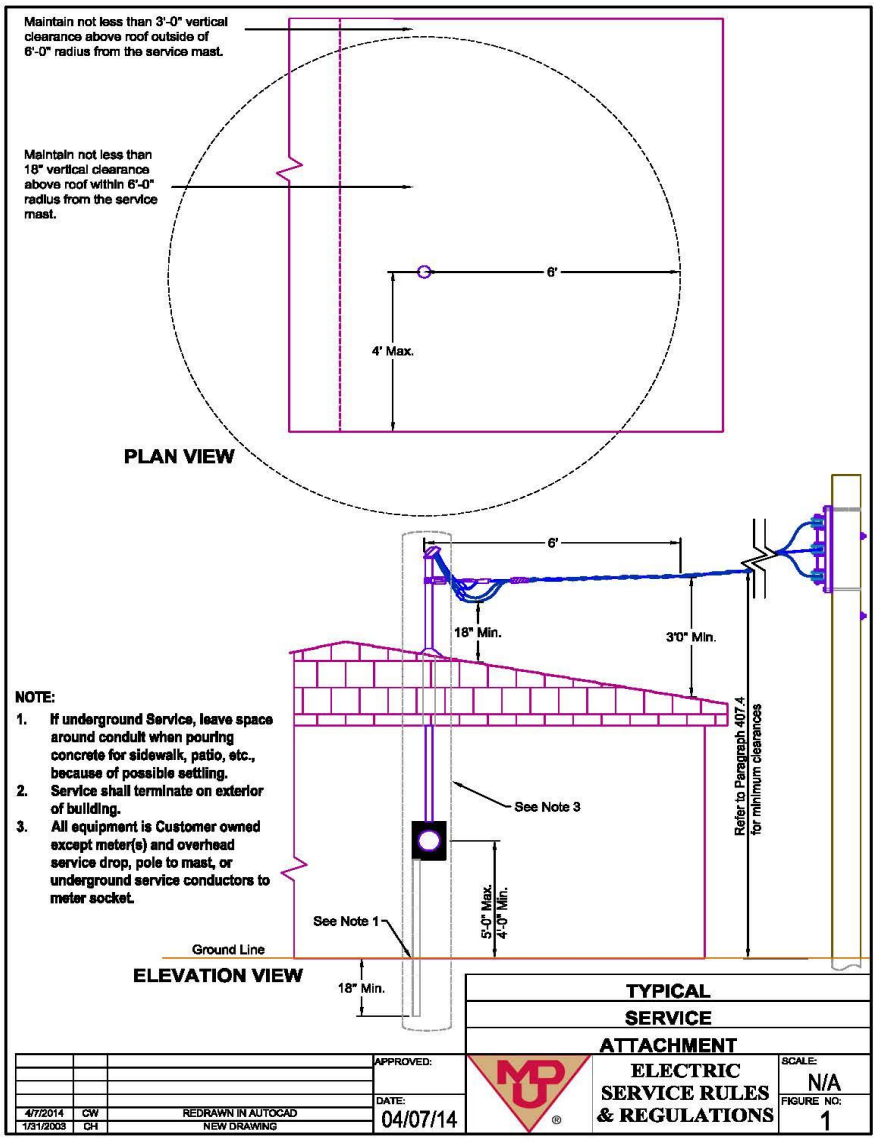
711. Carrier Equipment
The customer shall not impose, or cause to be imposed, any electric signal of any frequency or magnitude upon the Company's distribution system that may produce ill effects on Company equipment, affect safety of personnel or affect other Customers' equipment.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 90.48

CONDITIONS OF SERVICE Rate 100



Date Filed: June 30, 2025

Effective Date: Service rendered on and after

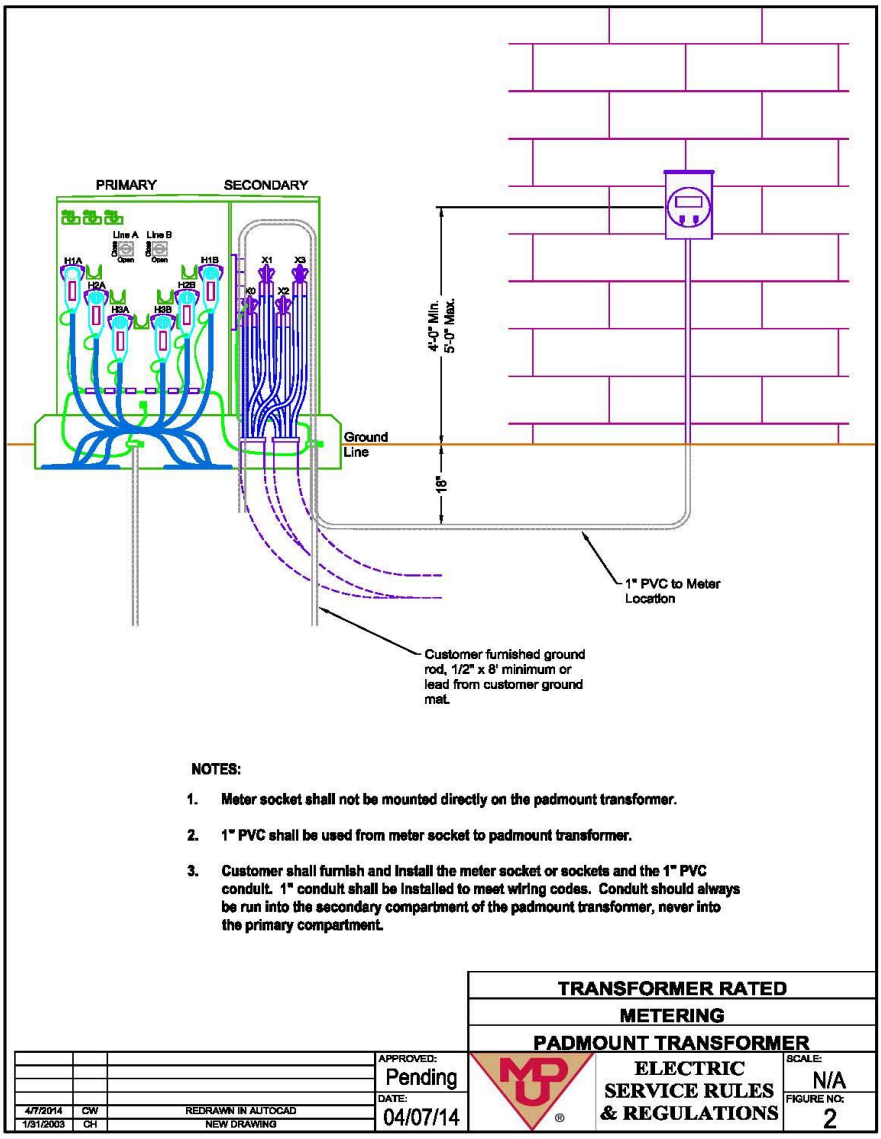
Issued By: Travis R. Jacobson
Vice President – Regulatory Affairs

Docket No.:

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100



Date Filed: June 30, 2025

Effective Date: Service rendered on and after

Issued By: Travis R. Jacobson
Vice President– Regulatory Affairs

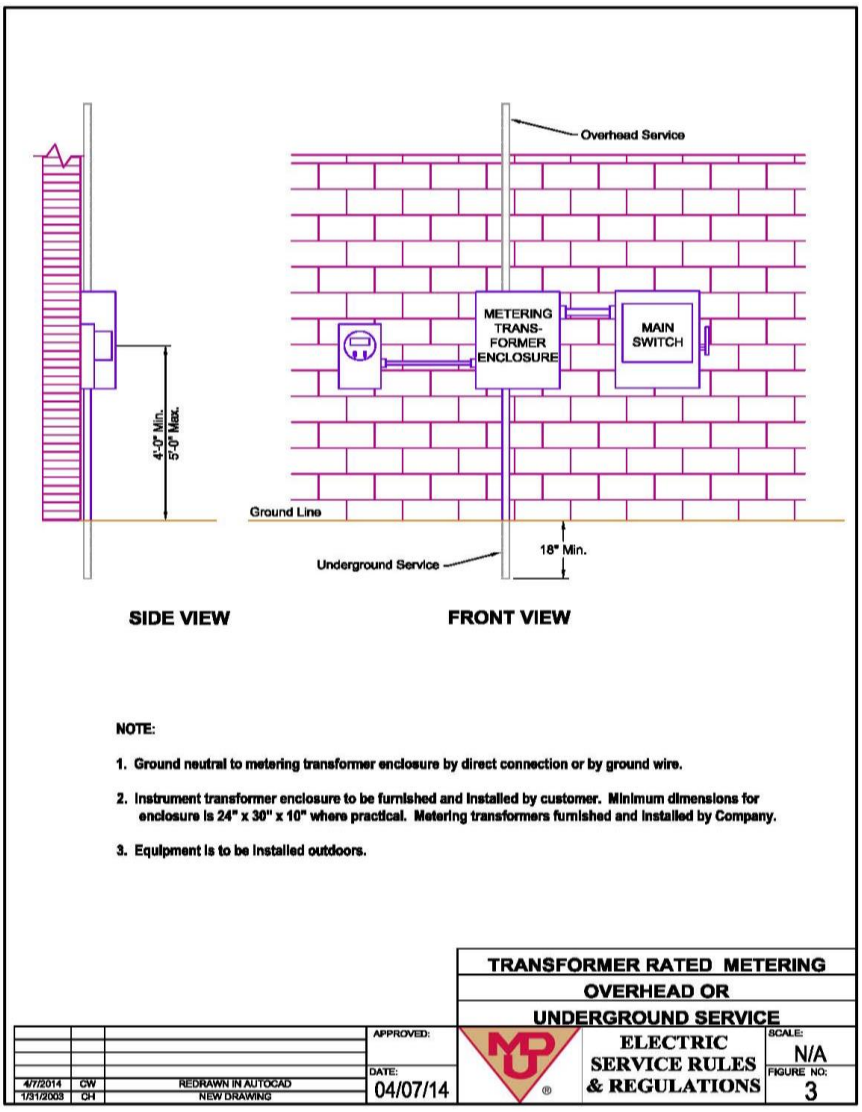
Docket No.:

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 90.50

CONDITIONS OF SERVICE Rate 100



Date Filed: June 30, 2025

Effective Date: Service rendered on and after

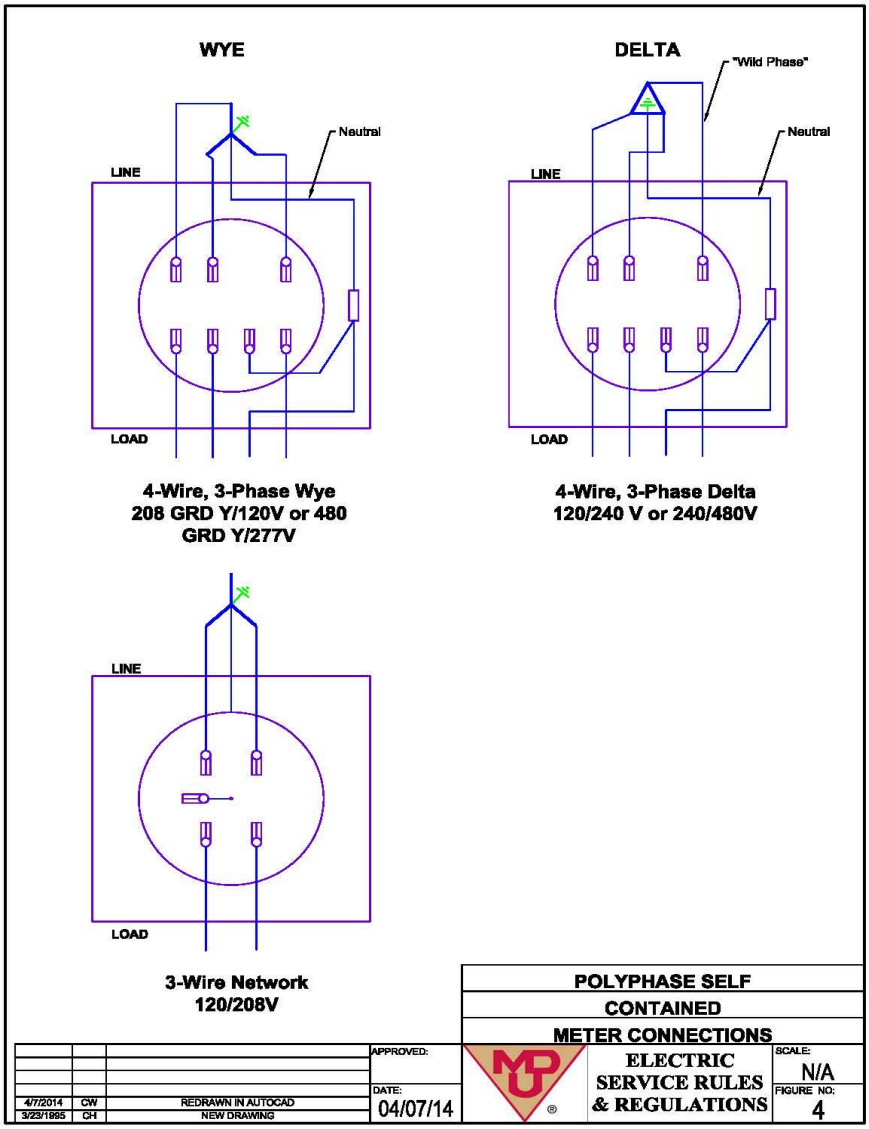
Issued By: Travis R. Jacobson
Vice President – Regulatory Affairs

Docket No.:

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100



Date Filed: June 30, 2025

Effective Date: Service rendered on and after

Issued By: Travis R. Jacobson
Vice President – Regulatory Affairs

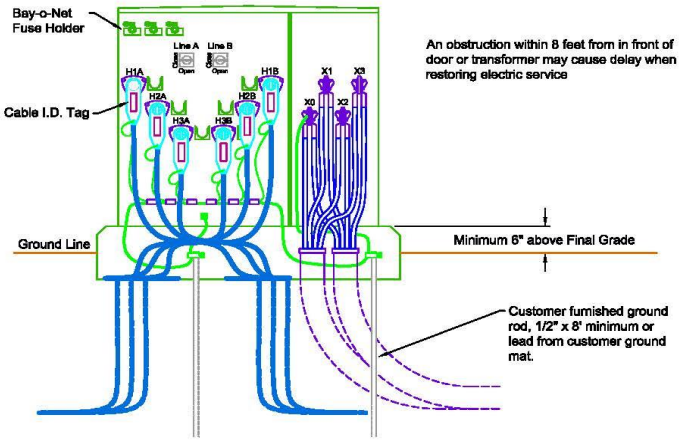
Docket No.:

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 90.52

CONDITIONS OF SERVICE Rate 100



NOTES:

1. Consult with Company for actual equipment pad dimensions.
2. Transformer pad, service cable, conduit and ground rod or mat for service cable grounding are furnished by Customer.
3. Allow sufficient slack in service entrance conductor to allow for proper connection to equipment terminals.
4. Service connectors to be furnished by Company.
5. Connection to Company's equipment terminals to be made by Company.
6. When more than four condutors are installed for each phase, consult Company for transition cabinet requirements.

TRANSFORMER LOCATION

1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with bollards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.

			APPROVED: Pending	TYPICAL PADMOUNT EQUIPMENT INSTALLATION	SCALE: N/A
			DATE: 04/07/14	ELECTRIC SERVICE RULES & REGULATIONS	FIGURE NO: 5
4/7/2014	CW	REDRAWN IN AUTOCAD			
1/31/2003	CH	NEW DRAWING			

Date Filed: June 30, 2025

Effective Date: Service rendered on and after

Issued By: Travis R. Jacobson
Vice President – Regulatory Affairs

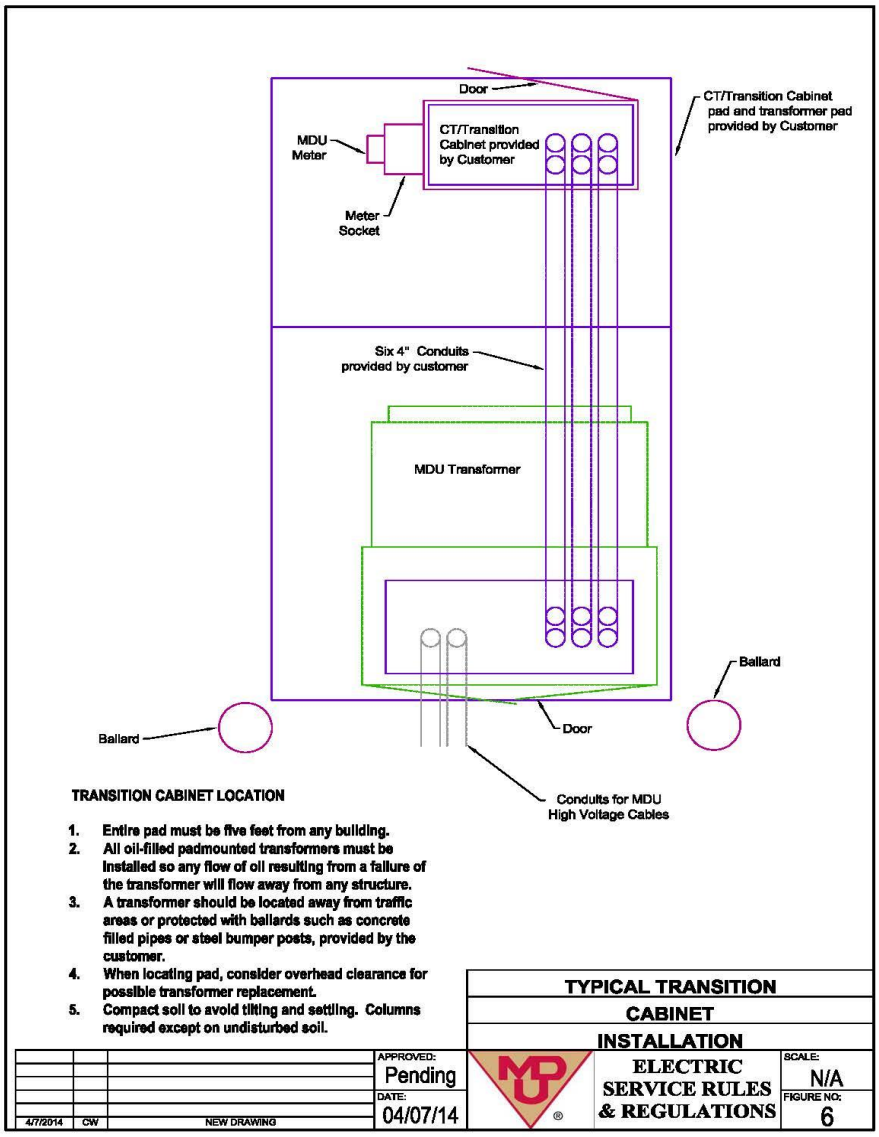
Docket No.:

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 90.53

CONDITIONS OF SERVICE Rate 100



Date Filed: June 30, 2025

Effective Date: Service rendered on and after

Issued By: Travis R. Jacobson
Vice President – Regulatory Affairs

Docket No.:

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 160

ELECTRIC EXTENSION POLICY
Rate 104

The policy of Montana-Dakota Utilities Co. for electric extensions is to provide service to any new customer.

1. A permanent extension may be constructed without a customer or developer contribution if the estimated project cost is equal to or less than 3.781 times the estimated annual revenue excluding power supply costs (3.781 to 1 ratio).

2. If the estimated project cost is greater than 3.781 times the estimated annual revenue excluding power supply costs, the extension will be made only with a customer contribution, which may be refundable.

    a. Contribution -

        1) When a contribution is required of any customer, with the exception of those customers defined in 2) below, the formula for determining the amount of the contribution required shall be as follows: Total project cost less 3.781 times annual revenue excluding power supply costs equals contribution amount.

        2) The contribution requirement for developers of subdivisions and industrial customers shall be the estimated project cost.

        3) The contribution shall be a one-time payment prior to construction.

        4) A minimum annual bill equal to the estimated annual revenue used in the contribution formula, will be applicable for a period of five (5) years. This amount will be as set forth on the Electric Service Agreement.

        5) Upon completion of construction, where actual costs are less than the estimated construction costs, a refund will be made for the difference, but not for an amount less than $25.00. No additional contribution will be requested from the customer where actual construction costs exceed the estimate unless unusual construction difficulties are encountered.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 160.1

ELECTRIC EXTENSION POLICY
Rate 104

b. Refund -

1) If within a five-year period from the date initial service is established, one or more additional customers are added to the above-referred-to extension, Company shall recompute the contribution required by combining the proposed project costs for the new customer(s) with the project costs of those customers already taking service. If, by so combining the project costs, the contribution of those customers already taking service would be less, Company shall make a proportionate refund, without interest, to those customers taking service prior to commencement of service to said additional customer(s).

2) If a customer makes a refundable contribution, the Company will refund to the customer annually, for a period of five years from the date service becomes available to the customer, an amount equal to fifty percent of the customer's bill, after first deducting the annual minimum, which minimum shall be equal to the estimated annual revenue excluding power supply costs used in the contribution formula, provided, however, that no refunds shall be made in excess of the amount contributed. The annual refund shall be paid only after the electric service bills for that year have been paid in full.

3) Refunds for developers of subdivisions shall be made for each lot connected based on the following calculation: Total refundable contribution divided by the number of lots that can be served from the extension equals refund per lot. In addition, the total revenue excluding power supply costs of the subdivision will be reviewed annually to determine if adequate revenues are being generated so that the contribution formula would indicate a zero contribution. When this revenue level is reached, a refund will be made to the developer equal to the remaining contribution amount still held by the Company.

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

State of Wyoming
Electric Rate Schedule

ELECTRIC EXTENSION POLICY
Rate 104

4) No refund shall be made by Company to customer(s) or developer after the aforementioned five-year period has expired.

5) No interest will be paid by Company to customer(s) on any amount customer(s) has paid to Company as a contribution in aid of construction for the project.

3. Project cost shall exclude the service line(s), transformer(s), and meter. The service line is considered to be the low voltage conductors between the Company owned transformer or secondary system and the customer owned service entrance equipment.

4. Company will deliver electricity to customer at the same rate approved by the Wyoming Public Service Commission.

5. Where a contribution in aid of construction is required to provide service, such extension is subject to prior execution by customer and Company of Company's standard agreement for extensions.

6. Where abnormal conditions exist, causing extraordinary costs on any part of the extension (e.g., railroad or river crossing, land clearing, special permits, etc.), a charge may be made equal to the additional cost incurred by reason of the abnormal conditions.

7. Temporary loads, such as gravel pit operations, carnivals, etc., shall follow the Company rules for temporary services.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 165

DARK SKY LIGHTING SERVICE
Rate 105

AVAILABILITY:

Optional customer owned lighting apparatus defined as any shield, cover or other device that is designed to minimize light illuminating unintended areas and maintain dark skies in accordance with Wyoming Statute Annotated §37-16-201 to 202. Such lighting fixture shall be used with or on a lamp served by Company under an otherwise applicable electric service rate schedule.

RATE:

Customer requesting such lighting apparatus shall be required to pay in full the actual cost of the materials and installation prior to installation of lighting apparatus.

GENERAL TERMS AND CONDITIONS:

1. Costs for the lighting apparatus shall be not subsidized by revenue from other Company provided services.

2. The Customer shall request in writing the lighting apparatus to be installed, the location of the installation and the illumination control desired.

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 167

SERVICE INTERRUPTION REPORTING PLAN
Rate 106

The following sets forth the Company's Service Interruption Reporting Plan as required in Chapter 3, Section 27-28 of the Wyoming Public Service Commission's (Commission) Rules applicable to service provided by the Company in its Wyoming service territories.

A. Definitions of Service Interruptions:

1. Major Service Interruption shall be defined as:

   a. An event that results in estimated property damage of at least $50,000;

   b. An event that results in death, in-patient hospitalization, damage to the Company's property which substantially affects service to the public or is otherwise significant in the judgement of the Company;

   c. A sustained single feeder outage of two hours or longer to the lesser of 500 customers or 50 percent of the customers served;

   d. The loss of service to a distribution substation feeder or;

   e. Any service interruption which affects twenty five (25) or more customers for eight (8) hours or longer.

   Minor Service Interruption shall be defined as any sustained service interruption which affects at least one customer and is not defined as a Reportable Incident.

2. Scheduled Service Interruption shall be defined as:

   a. Any service interruption scheduled by the Company which is expected to last four (4) hours or longer, or

   b. Any sustained service interruption scheduled by the Company which is expected to affect twenty-five (25) or more customers.

   Sustained Reportable Incident shall be defined as any service interruption lasting more than five (5) minutes.

B. Customer Notification Requirements:

1. Reasonable effort will be made to notify affected customers at least forty-

eight (48) hours prior to a Scheduled Service Interruption. Scheduled Service Interruptions that will occur on a Monday will require customer notification on the previous Thursday.

2. In the event of an emergency causing the Company to take a Scheduled Service Interruption in less than forty-eight (48) hours, customers will be notified as soon as practical.

C. Commission Notification Requirements:

1. Scheduled Service Interruption:
   a. The Commission will be notified at least forty-eight (48) hours prior to a Scheduled Service Interruption. Scheduled Service Interruptions that will occur on a Monday will require Commission notification on the previous Thursday.
   b. In the event of an emergency causing the Company to take a Scheduled Service Interruption in less than forty-eight (48) hours, the Commission will be notified as soon as practical.
2. Nonscheduled Service Interruption:
   a. The Commission will be notified within two (2) hours of the known commencement of a Reportable Incident using the Commission's Service Interruption Reporting Telephone number (SIRT). Within 24 hours, the Company will follow up with an email report in conformance with Chapter 3, Section 27(f) of the Commission's Rules.
   b. Reports to the Commission shall include, but not be limited to:
      i. Location and geographic extent;
      ii. Damage assessment, explaining the risks and likely effects on the public, the utility's customers, other utilities and telecommunications services;
      iii. Date and time the service interruption began;
      iv. Number of customers or individuals affected;
      v. Cause, if known;

vi. Estimated time of service restoration and basis for estimate;

vii. Any deaths or injuries;

viii. Efforts being undertaken to restore service;

ix. Efforts being undertaken to assist affected individuals;

x. Other governmental agencies notified;

xi. Contact information for reporting individual(s)

xii. If the event is ongoing, the time interval until the Commission will be updated; and

xiii. Any other information that may be necessary to assess threats or damage.

D. Commission Reporting Requirements:

1. Quarterly reports of all Service Interruptions greater than five minutes other than meter testing or change outs will be filed with the Commission within 30 days after the end of each calendar quarter in conformance with Chapter 3, Section 28 of the Commission's Rules.
2. These records shall be retained by the Company for a minimum of six years.
3. The Company shall annually review its Service Interruption Reporting Plan with any proposed modifications and definitions of major or minor service interruptions specific to the utility's system, filed with the Commission by May 1. If, after the Company's review, there is no change to the Service Interruption Reporting Plan, the Company shall so notify the Commission by letter by May 1.

E. Reportable Incident Contact Information:

1. The Company shall submit a list of contact personnel (names and phone numbers) to be contacted during a Major Reportable Incident.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 167.3

SERVICE INTERRUPTION REPORTING PLAN
Rate 106

2. The contact list shall be reviewed by Montana-Dakota and updated when necessary. The Company will also confirm the list remains current by notifying the Commission by January 1 and July 1 of each calendar year.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 185

ELECTRIC METER TESTING PROGRAM
Rate 115

APPLICABILITY:

This rate schedule specifies the protocol to be followed for the testing of electric meters in accordance with Chapter 3, Section 18 of the Commission Procedural Rules and Regulations (Commission Rules).

NEW METERS:

A sampling of 5% of new meters will be tested at full load and at light load. If any meter is found to be off more than ±1%, the entire lot will be tested or rejected.

RESIDENTIAL WATTHOUR METERS IN SERVICE:

1. A random selection of meters from each decade – 1980's, 1990's, etc., will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense. At the time the random selection is made, meters less than five years old and active meters that have been tested in the last five years, will be excluded from the population to be randomly sampled.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 96% of the meters shall be not more than +/- 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 96% of the meters in a given vintage class fail to meet the requirements of +/- 2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of four years. In the event the meter type failing the +/- 2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

COMMERICAL WATTHOUR METER IN SERVICE:

1. A random selection of solid state meters from each decade – 1980's, 1990's, etc. will be tested annually at full load and light load. The sample size will depend on

lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense. At the time the random selection is made, meters less than five years old and active meters that have been tested in the last five years, will be excluded from the population to be randomly sampled.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 98% of the meters shall be not more than +/- 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 98% of the meters in a given vintage class fail to meet the requirements of +/- 2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of two years. In the event the meter type failing the +/- 2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of two years rather than the entire vintage class.

INDUSTRIAL WATTHOUR METERS IN SERVICE:

1. A random selection of solid state meters from each decade – 1980's, 1990's, etc. will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense. At the time the random selection is made, meters less than five years old and active meters that have been tested in the last five years, will be excluded from the population to be randomly sampled.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 99% of the meters shall be not more than +/- 2% in error at both light load and full load, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

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

State of Wyoming
Electric Rate Schedule

ELECTRIC METER TESTING PROGRAM
Rate 115

4. Whenever it is found that less than 99% of the meters fail to meet these requirements, the entire vintage class will be tested and adjusted or, if more economic, replaced within two years. In the event the meter type failing the +/- 2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of two years rather than the entire vintage class.

METER TEST EQUIPMENT:

1. All equipment used for testing and calibration shall be cared for and maintained as recommended in the manufacturer's operating and maintenance manuals. Appropriate carrying cases designed for the purpose shall be used when such equipment is transported to and from its normal service location.

2. Meters and other equipment which will be used as a reference standard to certify other equipment shall be kept in a temperature stable environment and shall be calibrated annually except as noted herein.

3. Meters and other equipment which are used as a reference standard shall only be used for calibration purposes, and shall not be used for trouble shooting, corrective maintenance or any other activity which might jeopardize the integrity of the instrument for calibration accuracy.

4. Calibration of the items used by the utility for reference standards shall be accomplished by an instrument with a higher degree of accuracy than the item being calibrated with the accuracy of said instrument being traceable to the National Institute of Standards and Technology (NIST).

5. Current transformers are burden tested at the time the meter is tested. A field test set is connected in series with the secondary of the metering current transformer, at the test switch. The test switch is opened, and the transformer secondary is shorted out. Each current transformer is tested first at the maximum burden, and, if the current drops, the burden is decreased until no change is observed. Appendices with the test set are used to evaluate the results to determine if the current transformer is performing satisfactorily.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 185.3

ELECTRIC METER TESTING PROGRAM
Rate 115

6. Voltage transformers are tested by applying a test voltage to determine if the appropriate ratio is obtained.

7. Whenever any electric meter is tested, the test record shall be preserved, including the information necessary for identifying the meter, the reason for making the test, the reading of the meter upon removal from service and the result of the test, together with all data taken at the time of the test in sufficiently complete form to permit the convenient checking of the methods employed and the calculations for the life of the meter.

8. The Company shall perform meter testing using the equipment identified in the table below.

Type	Manufacturer	Used for	Degree of Accuracy	Calibration Interval
RM-17	Radian	Watt-hour Meter Standard	±0.05%	12 Months
RB-20	Radian	Watt-hour Meter Standard	±0.05%	12 Months

9. The Company shall perform calibration checks on the above identified testing equipment using the equipment identified in the table below.

Type	Manufacturer	Used to Test Equipment Types	Degree of Accuracy	Calibration Interval
RD-21	Scientific Columbus	RM-17 RB-20	See Note 1/	12 Months

Note 1/:
Accuracy: Errors expressed in percent of reading for normal operating conditions. Guaranteed accuracy specification includes stability, traceability, uncertainty, power factor, and test system errors.

1. Normal Operating Conditions:
   i. Ambient Temperature: -20°C to 70°C (-4°F to 158°F)
   ii. Relative Humidity: 0% to 95%
   iii. Auxiliary Power Voltage: 60 – 600 volts (Autoranging)
   iv. Frequency: 45 to 65 Hz
   v. Orientation: Any
2. Influences Affecting Accuracy:
   i. Temperature influence outside normal operating temperature range per °C: ±0.0005%
   ii. For Power Factors of 100% and 50% output for Whrs, VARhrs, VAhrs: no impact on accuracy
   iii. For power factor of <0.5 (PF between - 60° and -90°, then guaranteed accuracy is ±0.02%/PF.

10. These instruments are in turn calibrated with higher degree accuracy instruments annually. The highest degree accuracy instruments will be delivered to a manufacturer's facility once each year for calibration with their instruments that are directly traceable to the National Institute of Standards and Technology (NIST).

11. The referenced Military Standards are available for review by the customer by contacting the Company to discuss by phone or to arrange an appointment at the Company's Sheridan office.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 190

AUTOPAY PLAN
Rate 122

AVAILABILITY:

The AutoPay Plan provides customers the option to automatically have their electric service bill, including miscellaneous charges, deducted from their checking account. This option is available in all communities served by the Company to all customers who voluntarily agree to participate in the AutoPay Plan and who have not issued two or more NSF checks to the Company in the preceding 12 month period and are not currently utilizing the Low Income Energy Assistance Program (LIEAP).

GENERAL TERMS AND CONDITIONS:

1. All provisions set forth in customer's otherwise applicable standard rate schedule shall apply.

2. The Company will issue a bill each month to the customer.

3. The bill will indicate that the amount shown in the "Amount Due" column will be automatically deducted from the customer's checking account each month on the due date indicated on the customer's bill.

4. All customers who accept the AutoPay Plan shall sign an authorization form.

5. The Company has the right to remove a customer from the AutoPay Plan if the financial institution has advised the Company of two NSF check instances within the preceding 12 month period. Thereafter, customer shall be again eligible to participate in the AutoPay Plan in the future providing that the customer has complied with the "Availability" section above.

6. Customers utilizing the AutoPay Plan who subsequently use the LIEAP will be removed from the AutoPay Plan by the Company.

7. The customer may cancel the use of the AutoPay Plan option by notifying the Company in writing.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 191

SUMMARY BILLING PLAN
Rate 123

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

State of Wyoming
Electric Rate Schedule

SUMMARY BILLING PLAN
Rate 123

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.
400 N 4th Street
Bismarck, ND 58501

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 200

BALANCED BILLING PLAN
Rate 125

1. SCOPE

A. The Plan provides electric customers with a method of paying for electric usage to avoid the highs and lows associated with normal monthly billing. The customer's monthly bill is computed by taking an average of the usage during the previous twelve months. Current energy rates are then applied to this average monthly usage to calculate the current payment due. Qualified customers with less than 12 month's history at their current premise are also allowed to enroll in the Plan.

B. Monthly bills rendered under this Plan, as indicated in A. above, will be based upon a moving average consumption and will normally change each month. The moving average will change slightly each month and thus appropriate dollar adjustments will be made to the billed amount each month.

C. The provisions of this Plan are applicable to all residential customers in Wyoming. Certain nonresidential electric customers served in Wyoming may qualify. Accordingly, the following nonresidential customers do not qualify for this Plan:

1. Industrial, municipal or interdepartmental electric customers.

2. Electric customers with demand meters.

3. Combination customers who have electric demand meters neither the gas and/or electric usage qualifies for the Plan.

4. Interruptible or otherwise controlled customers.

5. Seasonal, short-term or temporary customers.

6. Customers whose accounts are delinquent and who have not signed a Deferred Payment Agreement.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 200.1

BALANCED BILLING PLAN
Rate 125

7. Customers whose usage patterns are not sufficiently predictable so as to permit estimation on an annual basis with a reasonable degree of certainty.

2. PROCEDURE

A. Customers must contact Company to request enrollment in the Balanced Billing Plan.

B. If the customer's account is current and otherwise qualifies for enrollment in the Plan as provided in Section I.C., the customer will be so informed at the time of customer's request and the customer's account record in the Customer Information System will be so coded.

C. As indicated in Section 1.C.6., customers who are delinquent cannot qualify for the Plan unless they are able to pay any amounts past due or enter into a Deferred Payment Agreement with the Company. The customer agrees to pay a reasonable fixed amount each month in addition to the Balanced Billing Plan payment amount until such arrears are paid in full.

D. Customers enrolled in the Plan will continue to be billed under the Plan provisions until they request removal or they are sixty days in arrears and are removed from the Plan by the Company.

E. If a customer desires to be removed from the Plan, customer must contact Company to request withdrawal from the Plan. Removal from plan will be effective following contact regarding withdrawal. Upon such removal the total unpaid balance becomes due at the next billing cycle. If a credit balance exists it may be refunded or applied to the next cycle billing, at the customer's discretion.

F. If a customer is removed from the Plan due to delinquency as indicated above, the total unpaid balance in their account becomes due and payable.

Tariffs Reflecting Proposed Changes

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Title Sheet

TITLE SHEET

WYOMING P.S.C. TARIFF NO. 2~~1~~
Including
Schedule of Rates for Electric Service
and
Rules

OF

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

400 N 4th Street

BISMARCK, NORTH DAKOTA 58501

Filed with the

WYOMING PUBLIC SERVICE COMMISSION

Date Filed:	~~January 4, 2019~~June 30, 2025	**Effective Date:**	Service rendered on and after ~~January 1, 2019~~
Issued By:	~~Tamie A. Aberle~~Travis R. Jacobson ~~Director~~Vice President~~—~~ Regulatory Affairs	**Docket No.:**	~~20004-128-EA-18~~

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~2nd Revised~~ Original Sheet No. 1
~~Canceling 1st Revised Sheet No. 1~~

TABLE OF CONTENTS

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. 3

COMMUNITIES SERVED

COMMUNITIES SERVED

Acme	Ranchester
Big Horn	*Sheridan
Dayton	Story

*Designates District Office

Montana-Dakota Sheridan District Office
2324 Dry Ranch Road
Sheridan, WY 82801
1.800.638.3278

Date Filed:	~~January 4, 2019~~June 30, 2025	**Effective Date:**	Service rendered on and after ~~January 1, 2019~~
Issued By:	~~Tamie A. Aberle~~Travis R. Jacobson ~~Director~~Vice President – Regulatory Affairs	**Docket No.:**	~~20004-128-EA-18~~

Montana-Dakota Utilities Co.
~~*A Subsidiary of MDU Resources Group, Inc.*~~
400 N 4th Street
Bismarck, ND 58502

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. ~~21~~
~~8th~~ Revised Original Sheet No. 4
~~Canceling 7th Revised Sheet No. 4~~

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Demand Charge Per Kw	Energy Charge Per Kwh	PSCA Per Kwh 1/	RSIR 2/	Total Per Kwh
Residential Rate 10	6	$1.160 per day				0.00%	
Energy Charge:		~~$0.769~~		$0.06291	$0.04422		$0.10713
~~First 1,000 Kwh per month~~				~~$0.04229~~	~~$0.05127~~		~~$0.09426~~
~~Over 1,000 Kwh per month~~				~~$0.06171~~	~~$0.05127~~		~~$0.11298~~
Special Residential Controlled Rate 11	10	$0.194 per day				0.00%	
Energy Charge:		~~$0.167~~		$0.04733	$0.04422		$0.09155
				~~$0.02089~~	~~$0.05127~~		~~$0.07216~~
Small General Rate 20	20						
Demand Metered							
Primary Service:		$3.000 per day				0.00%	
Demand Charge:		~~$0.923~~	~~$5.15~~				
First 10 Kw or less of billing demand			$8.76				
Over 10 Kw per month of billing demand			$14.75				
Energy Charge:			~~$9.83~~	$0.02804	$0.03902		$0.06706
				~~$0.02221~~	~~$0.04546~~		~~$0.06767~~
Secondary Service:		$1.380 per day				0.00%	
Demand Charge:		~~$0.923~~	~~$5.62~~				
First 10 Kw or less of billing demand			$9.55				
Over 10 Kw per month of billing demand			$15.45				
Energy Charge:			~~$10.30~~	$0.02992	$0.04422		$0.07414
				~~$0.01968~~	~~$0.05127~~		~~$0.07095~~
Small General Rate 20	20	$1.380 per day				0.00%	
Non Demand Metered		~~$0.923~~					
Energy Charge				$0.03771	$0.04422		$0.08193
				~~$0.02526~~	~~$0.05127~~		~~$0.07653~~
~~Special General Controlled Electric Service Rate 22~~	~~25~~	~~$0.215 per day~~					
~~Energy Charge:~~				~~$0.01998~~	~~$0.05127~~		~~$0.07125~~
Outdoor Lighting Rate 24	30					0.00%	
Energy Charge				$0.03323	$0.04422		$0.07745
				~~$0.02531~~	~~$0.05127~~		~~$0.07658~~
Irrigation Power Rate 25	35	$2.868 per day				0.00%	
Demand Charge		~~$1.54~~	$11.50				
Energy Charge			~~$6.55~~	$0.02737	$0.04422		$0.07159
				~~$0.02257~~	~~$0.05127~~		~~$0.07384~~
Irrigation Power Time of Day Rate 26	37	$2.750 per day				0.00%	
Demand Charge:		$1.54	~~$7.77~~				
On-Peak Demand			$13.50				
Off-Peak Demand			$5.00				
Energy Charge			~~$2.81~~	$0.04624	$0.04422		$0.09046
				~~$0.03850~~	~~$0.05127~~		~~$0.08977~~

1/ Sheet No. 58
2/ Sheet No. 60. Applicable to amounts billed under Basic Service Charge, Energy Charge, and Demand Charges.

Date Filed: ~~February 28, 2025~~June 30, 2025

Issued By: Travis R. Jacobson
Vice President - Regulatory Affairs

Effective Date: Service rendered on and after ~~May 1, 2025~~

Docket No: ~~20004-170-EM-24~~
~~Record No. 17767~~

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 21
~~15th Revised~~ Original Sheet No. 4.1
~~Canceling 14th Revised Sheet No. 5~~

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Demand Charge Per Kw	Energy Charge Per Kwh	PSCA Per Kwh 1/	RSIR 2/	Total Per Kwh
Large Power Standby Rate 37	40					0.00%	
Primary Serivce:		$300.00 per mo.					
Contract Demand Charge		~~$150.00 month~~	$15.64				
Energy Charge:			~~$11.73~~	$0.01131	$0.03902		$0.05033
Secondary Service:				~~$0.01129~~	~~$0.04546~~		~~$0.05675~~
Contract Demand Charge		$95.00 per mo.					
Energy Charge		~~$66.00 month~~	$15.28				
			~~$12.20~~	$0.00479	$0.04422		$0.04901
				~~$0.00478~~	~~$0.05127~~		~~$0.05605~~
Interruptible Large Power Demand						0.00%	
Response Rate 38	43						
Primary Service		$300.00 per mo.					
Demand Charge			$16.14				
Demand Response Credit			$2.75				
Energy Charge				$0.01131	$0.03902		$0.05033
Secondary Service:		$95.00 per mo.					
Demand Charge			$15.78				
Demand Response Credit			$2.75				
Energy Charge				$0.00479	$0.04422		$0.04901
Large General Rate 39	45					0.00%	
Primary Service		$300.00 per mo.					
Demand Charge		~~$150.00 month~~	$16.14				
Energy Charge			~~$11.23~~	$0.01131	$0.03902		$0.05033
				~~$0.01129~~	~~$0.04546~~		~~$0.05675~~
Secondary Service:		$95.00 per mo.					
Demand Charge		~~$66.00 month~~	$15.78				
Energy Charge			~~$11.70~~	$0.00479	$0.04422		$0.04901
				~~$0.00478~~	~~$0.05127~~		~~$0.05605~~
Public ~~Municipal~~ Lighting Rate 41	50					0.00%	
Energy Charge				$0.07230	$0.04422		$0.11652
				~~$0.05507~~	~~$0.05127~~		~~$0.10634~~
Parallel Generation Rate 57	70					0.00%	
Partial Requirement:		~~month~~					
Single Phase		$3.30 per mo.					
Three Phase		$9.34 per mo.					
Energy Payment		~~month~~		$0.03448	Not Applicable		$0.03448
Parallel Generation		~~month~~					
Single Phase		$13.68 per mo.					
Three Phase		$17.25 per mo.					
Capacity Payment		~~month~~	$8.29				
Energy Payment				$0.03448	Not Applicable		$0.03448

1/ Sheet No. 58
2/ Sheet No. 60. Applicable to amounts billed under Basic Service Charge, Energy Charge, and Demand Charges.

Date Filed: ~~May 23, 2025~~June 30, 2025

Issued By: Travis R. Jacobson
Vice President - Regulatory Affairs

Effective Date: Service rendered on and after ~~June 1, 2025~~

Docket No: ~~20004-171-ET-25~~
~~Record No. 17778~~

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
1st ~~Revised~~ Original Sheet No. 6
~~Canceling Original Sheet No. 6~~

RESIDENTIAL ELECTRIC SERVICE
Rate 10

AVAILABILITY:

In all communities served for single-phase residential electric service through one meter in a single private residence for all domestic uses.

RATE:

Basic Service Charge: $1.160~~0.769~~ per day

Energy Charge: 6.291¢ per Kwh
~~First 1,000 Kwh per month 4.299¢ per Kwh~~
~~Over 1,000 Kwh per month 6.171¢ per Kwh~~

~~Power Supply Cost~~ Adjustment Clauses: ~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

~~POWER SUPPLY COST ADJUSTMENT:~~

~~Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.~~

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 6
~~Canceling Original Sheet No. 6~~

RESIDENTIAL ELECTRIC SERVICE
Rate 10

GENERAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~2nd Revised~~ Original Sheet No. 10
~~Canceling 1st Revised Sheet No. 10~~

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11 (CLOSED TO NEW CUSTOMERS)

AVAILABILITY:

In all communities served for single-phase residential electric service customers who operate Company approved interruptible electric space heating equipment so arranged to allow remote operation by the Company and subject to the Company's ability to control such equipment. This rate schedule is restricted to active services installed on a customer's premise on or before August 2, 2022.

Controlled electric water heating service is also available under this rate in conjunction with controlled space heating. The customer's primary source of space heating shall be electric and the customer shall be responsible for providing a secondary source of space heating. The main energy used in backup systems cannot be firm electric service. Domestic uses other than controlled space heating and controlled water heating will be served under Residential Electric Service Rate 10.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving water heating and space heating facilities with no provision for connecting other loads thereto. The customer's secondary system controls, circulating fans and pumps and all other alternate fuel related equipment shall be served as uncontrolled load. Unless otherwise specified by the Company, the point of delivery and service voltage for this service shall be the same as for the customer's other electric service.

RATE:

Basic Service Charge:	$0.194~~167~~ per day
Energy Charge:	4.733~~2.089~~¢ per Kwh

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~2nd Revised~~ Original Sheet No. 10
~~Canceling 1st Revised Sheet No. 10~~

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11 (CLOSED TO NEW CUSTOMERS)

~~Power Supply Cost~~ Adjustment Clauses: ~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:
Basic Service Charge.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~11~~10.1

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11 (CLOSED TO NEW CUSTOMERS)

PAYMENT:

Bills 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 or any amendments or alterations thereto.

~~POWER SUPPLY COST ADJUSTMENT:~~

~~Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.~~

~~CONTRACT TERMS:~~

~~The customer agrees to contract for service under the Special Residential Controlled Electric Service rate for a minimum period of one year. If the customer fails to continue service for the initial annual period, the customer will be billed for the difference between the customer's actual billing under Rate 11 and what would have been billed under Rate 10. At the end of a one year period, the customer will have the option of remaining under the Special Residential Controlled Electric Service rate or of returning to the Residential Electric Service rate.~~

GENERAL TERMS AND CONDITIONS:

1. Electric space and water heating equipment shall be designed to operate at a nominal voltage of 208, 240, or 277 volts, shall be separately metered and separately circuited, shall be permanently installed and the electric heating equipment shall be the principal source of space heating.

2. All installations must meet the minimum standards of the National Electrical Code so that the equipment will operate in a satisfactory manner and not interfere with other operations of the Company's system. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations for heating to make sure their equipment, insulation and building construction will meet requirements and receive adequate service.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~12~~10.2

SPECIAL RESIDENTIAL CONTROLLED ELECTRIC SERVICE Rate 11 (CLOSED TO NEW CUSTOMERS)

3. The customer must connect the interruptible electrical circuit(s) so as to allow interruptions through a Company owned contactor(s). A maximum of two contactors shall be provided by Company up to a maximum rating of 5 amps for one and 30 amps for the other. The customer must wire into a connection point designated by Company to allow installation of control equipment by Company. The customer must provide a continuous 240 volt AC power source at the connection point for operation of the Company's control system.

4. The Company recommends that the installed capacity of electric water heating equipment be sufficient to provide the required volume of hot water giving consideration to the interruptions to be experienced and to permit maximum utilization of the rate for the benefit of the customer.

5. Service hereunder shall be available at the time control equipment is actually installed by the Company.

6. The Company shall not be liable for loss or damage caused by interruption of service.

7. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~8th Revised~~ Original Sheet No. 15
~~Canceling 7th Revised Sheet No. 15~~

RENEWABLE ENERGY RIDER
Rate 15

AVAILABILITY:
In all communities served by the Company in the State of Wyoming. The Renewable Energy Rider is available on an optional basis to customers receiving service under the Company's Electric Service Rate Schedules.

CHARGE PER BLOCK:
One (1) Block: $0.01 per month

One Block equals 100 Kwh of Renewable Energy Credit purchases.

MONTHLY BILL:
The Monthly Bill shall be the number of Blocks the customer has agreed to purchase multiplied by the Charge per Block. The Monthly Bill is in addition to all other charges contained in the customer's applicable rate schedule. The Monthly Bill shall be applied to the customer's billing regardless of actual energy consumption.

RENEWABLE ENERGY CREDIT:
A Renewable Energy Credit represents the intangible environmental attributes associated with producing one MWh of electricity from a renewable resource such as wind, solar or biomass. The Company will purchase Renewable Energy Credits as needed to match the number of Blocks purchased under this rate schedule. One Renewable Energy Credit equals 1,000 Kwh (1 MWh) of electricity from a renewable resource. Each Block is equivalent to one-tenth (1/10) of a Renewable Energy Credit.

GENERAL TERMS AND CONDITIONS:
1. Customers may apply for this rate any time during the year.

2. The Company will purchase Renewable Energy Credits to match purchases under this rate schedule. Due to timing differences, the purchase of Renewable Energy Credits may not directly correspond to customer purchases in an individual 12 month period.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. ~~16~~15.1
~~Canceling Original Sheet No. 16~~

RENEWABLE ENERGY RIDER
Rate 15

3. All funds collected and expenses associated with this program will be separately identified and tracked. Interest shall be credited in the case of net over collections at one-twelfth of the Commission's Authorized Interest Rate specified in accordance with Chapter 1, Section 3~~2~~(a)(xvii) of the Wyoming Public Service Commission's Rules. The Charge per Block is subject to change on an annual basis.

4. The commitment to purchase Blocks under this Rider will be for a minimum of a one year period and will continue on a monthly basis thereafter until the customer provides notice to either change or end participation. Requests for early withdrawal due to extenuating circumstances will be considered.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 20
~~Canceling Original Sheet No. 20~~

SMALL GENERAL ELECTRIC SERVICE
Rate 20

AVAILABILITY:

In all communities served for all types of general electric service with billing demands of 50 kilowatts or less, except customers covered by special contracts, or other rate schedules applicable to specific services. The customer's wiring must be so arranged that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

RATE:

Demand Metered ~~Basic~~ Service ~~Charge~~: ~~$0.923 per day~~

Primary Service:

Basic Service Charge: $ 3.000 per day

Demand Charge:

First 10 Kw or less of billing demand	$ 8.76~~5.15~~ per Kw
Over 10 Kw per month of billing demand	$14.75~~9.83~~ per Kw

Energy Charge: 2.804~~2.221~~¢ per Kwh

~~Power Supply Cost Adjustment:~~
~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Secondary Service:

Basic Service Charge: $ 1.380 per day

Demand Charge:

First 10 Kw or less of billing demand	$ 9.55~~5.62~~ per Kw
Over 10 Kw per month of billing demand	$15.45~~10.30~~ per Kw

Energy Charge: 2.992~~1.968~~¢ per Kwh

Date Filed:	~~April 4, 2019~~June 30, 2025	**Effective Date:**	Service rendered on and after ~~May 1, 2019~~
Issued By:	~~Tamie A. Aberle~~Travis R. Jacobson ~~Director~~Vice President – Regulatory Affairs	**Docket No.:**	~~20004-135-ER-18~~

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 20
~~Canceling Original Sheet No. 20~~

SMALL GENERAL ELECTRIC SERVICE
Rate 20

~~Power Supply Cost Adjustment:~~
~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Non Demand Metered ~~Basic~~ Service ~~Charge~~:	~~$0.923 per day~~
Basic Service Charge:	$1.380 per day

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
1~~st Revised~~ Original Sheet No. ~~21~~20.1
~~Canceling Original Sheet No. 21~~

SMALL GENERAL ELECTRIC SERVICE
Rate 20

Energy Charge: 3.771~~2.526~~¢ per Kwh

~~Power Supply Cost~~ Adjustment Clauses:

~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

~~POWER SUPPLY COST ADJUSTMENT:~~

~~Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.~~

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the maximum 15-minute measured demand in the current month. Demand will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power

factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

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

State of Wyoming
Electric Rate Schedule

SMALL GENERAL ELECTRIC SERVICE
Rate 20

GENERAL TERMS AND CONDITIONS:

1. All installations must meet the minimum standards of the National Electrical Code so that the equipment will operate in a satisfactory manner, and not interfere with other operations of the Company's system. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. At its discretion, the Company may install a demand meter on any customer's service whose average monthly usage exceeds 4,000 Kwh or who has an average peak demand greater than 10 Kw in any given twelve month period.

3. Non-metered services. At the Company's discretion, the installation of a meter on a customer's service may not be warranted. In the absence of measuring a customer's use, customers will be billed a predetermined energy use amount each month based on the operating characteristics of the equipment being served, such as Wi-Fi equipment served on Company-owned poles.

4~~3~~. The primary service rate is applicable to customers that own their own transformers, related equipment, and distribution facilities downstream of the meter, satisfactory to the Company so customers can receive service and be metered at primary voltages of 2,400 volts or greater.

5~~4~~. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 21
2nd Revised Sheet No. 25
Canceling 1st Revised Sheet No. 25

SPECIAL GENERAL CONTROLLED ELECTRIC SERVICE Rate 22

AVAILABILITY:

In all communities served for small and large general electric service customers (as defined in the availability sections of Small General Electric Service Rate 20 and Large General Electric Service Rate 39) who operate Company approved controlled electric equipment so arranged to allow remote operation by the Company and subject to the Company's ability to control such equipment. This rate schedule is restricted to active services installed on a customer's premise on or before August 2, 2022.

Company approved controlled electric equipment shall constitute equipment associated with loads directly contributing to the Company's system peak(s) as determined and accepted by the Company. The customer shall be responsible for providing alternate energy backup systems or equipment as required. The main energy used in backup systems cannot be firm electric service.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving approved controlled facilities with no provision for connecting other loads thereto. The customer's backup system controls or equipment controls shall be served as firm load. Unless otherwise specified by the Company, the point of delivery and service voltage for this service shall be the same as for any other electric service provided to the customers.

RATE:

Basic Service Charge:	$0.215 per day
Energy Charge:	1.998¢ per Kwh
Power Supply Cost Adjustment:	Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate

MINIMUM BILL:

Basic Service Charge

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 26

SPECIAL GENERAL CONTROLLED ELECTRIC SERVICE Rate 22

PAYMENT:

Bills 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 or any amendments or alterations thereto.

POWER SUPPLY COST ADJUSTMENT:

Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

CONTRACT TERMS:

The customer agrees to contract for service under the Special General Controlled Electric Service rate for a minimum period of one year. If the customer fails to continue service for the initial annual period, the customer will be billed for the difference between the customer's actual billing under Rate 22 and what would have been billed under the otherwise applicable General Service rate. At the end of a one year period, the customer will have the option of remaining under the Special General Controlled Electric Service rate or of returning to the otherwise applicable General Service rate.

GENERAL TERMS AND CONDITIONS:

1. Electric equipment shall be designed to operate at a nominal voltage of 208, 240, 277, or 480 volts, shall be separately metered and separately circuited, and shall be permanently installed.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 1
Original Sheet No. 27

SPECIAL GENERAL CONTROLLED
ELECTRIC SERVICE Rate 22

2. All installations must meet the minimum standards of the National Electrical Code so that the equipment will operate in a satisfactory manner and not interfere with other operations of the Company's system. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations for heating to make sure their equipment, insulation and building construction will meet requirements and receive adequate service.

3. The customer must connect the controlled electrical circuit(s) so as to allow interruptions through a Company owned contactor(s). A maximum of two contactors shall be provided by Company up to a maximum rating of 5 amps for one and 30 amps for the other. The customer must wire into a connection point designated by the Company to allow installation of control equipment by Company. The customer must provide a continuous 240 volt AC power source at the connection point for operation of the Company's control system.

4. The Company recommends that the installed capacity of electric water heating equipment be sufficient to provide the required volume of hot water giving consideration to the interruptions to be experienced and to permit maximum utilization of the rate for the benefit of the customer.

5. Service hereunder shall be available at the time control equipment is actually installed by the Company.

6. The Company shall not be liable for loss or damage caused by interruption of service.

7. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 30
~~Canceling Original Sheet No. 30~~

OUTDOOR LIGHTING SERVICE
Rate 24

AVAILABILITY:

For all outdoor lighting including flood lights, traditional or non-electronic billboard lighting and ~~metallic vapor~~ yard lights in all communities served. Lighting equipment may be Company-owned or customer-owned.

RATE:

Energy Charge: ~~———————~~3.323~~2.531~~¢ per Kwh

Kwh shall be computed according to the total rated capacity of the units in use.

~~Power Supply Cost~~ Adjustment Clauses:

~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

PAYMENT:

Bills 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 or any amendments or alterations thereto.

~~POWER SUPPLY COST ADJUSTMENT:~~

~~Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.~~

GENERAL TERMS AND CONDITIONS:

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 30
~~Canceling Original Sheet No. 30~~

OUTDOOR LIGHTING SERVICE
Rate 24

1. When service is not metered, the bill shall be computed on a~~n annual~~ daily basis, utilizing the minimum service requirement of 4,000 hours annually, and ~~one-twelfth shall be payable each month~~billed monthly to the customer.
2. Applicable to Company-owned facilities:
   a. The Company will install, own and operate the flood light(s), and yardlight(s) including a suitable reflector, bracket for mounting and automatic device to control operating hours set to operate from dusk to dawn.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~31~~30.1

OUTDOOR LIGHTING SERVICE
Rate 24

b. The Company will convert mercury vapor light units to high pressure sodium upon failure of existing mercury vapor units.

c. The light may be mounted on existing poles owned or controlled by the Company or ~~. The Company will furnish a 35 foot pole(s) for flood lights and a 30 foot pole(s) for yardlights at the customer's request at a separate rental rate if a special setting is required. If the customer chooses, the light may be installed~~ on a pole owned by the customer or other mounting point suitable for installation of the light. The conductors will be extended 100 feet per unit free of charge, but the customer shall pay for the extra cost of extensions of more than 100 feet per unit.

d. For Company-owned facilities, ~~In addition to the energy charge,~~ a monthly rental charge shall be rendered for each unit installed in addition to the energy charge. The customer should consult with the Company for such costs.

e. The Company will maintain the Company-installed and owned facilities when notified by customer or when noticed by Company personnel. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the customer for the cost of repair and replacement.

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
1st ~~Revised~~ Original Sheet No. 35
~~Canceling Original Sheet No. 35~~

IRRIGATION POWER SERVICE
Rate 25

AVAILABILITY:

For all irrigation power service, except customers choosing the Irrigation Power Service – Optional Time of Day Rate 26.

RATE:

Basic Service Charge:	$2.868~~1.54~~ per day
Demand Charge:	$11.50~~6.55~~ per Kw
Energy Charge:	2.737~~2.257~~¢ per Kwh

~~Power Supply Cost~~ Adjustment Clauses:

~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL: Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

~~POWER SUPPLY COST ADJUSTMENT:~~

~~Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.~~

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 35
~~Canceling Original Sheet No. 35~~

IRRIGATION POWER SERVICE
Rate 25

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the maximum 15-minute measured demand in the current month. Demand will be determined to the nearest one-tenth kilowatt.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~36~~35.1

IRRIGATION POWER SERVICE
Rate 25

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. Individual motors having a rating in excess of 10 horsepower must be three-phase. All wiring and other facilities beyond the point of metering shall be owned, operated, and maintained by the customer.

2. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 37
~~Canceling Original Sheet No. 37~~

IRRIGATION POWER SERVICE – OPTIONAL TIME OF DAY
Rate 26

AVAILABILITY:

For irrigation power service where customer chooses the optional time differentiated schedule for a minimum period of 12 months.

RATE:

Basic Service Charge: $2.750~~1.54~~ per day

Demand Charge:

On-Peak Demand: $ 13.50~~7.77~~ per Kw
Demand measured during peak hours designated as 4 p.m. to 6 p.m. local time Monday through Friday.

Off-Peak Demand: $ 5.00~~2.81~~ per Kw
Demand measured during all hours not covered by the on-peak rating period.

Energy Charge: 4.624~~3.850~~¢ per Kwh

~~Power Supply Cost~~ Adjustment Clauses:

~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL: Basic Service Charge.

PAYMENT:

Bills 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 or any amendments or alterations thereto.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
1st ~~Revised~~ Original Sheet No. 37
~~Canceling Original Sheet No. 37~~

IRRIGATION POWER SERVICE – OPTIONAL TIME OF DAY
Rate 26

~~POWER SUPPLY COST ADJUSTMENT:~~

~~Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.~~

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~38~~37.1

IRRIGATION POWER SERVICE – OPTIONAL TIME OF DAY
Rate 26

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the maximum 15-minute measured demand in the off-peak period and the maximum 15-minute measured demand in the on-peak period in the current month. Demand will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. Individual motors having a rating in excess of 10 horsepower must be three-phase. All wiring and other facilities beyond the point of metering shall be owned, operated, and maintained by the customer.

2. A customer choosing the optional time of day schedule shall remain on that schedule for a twelve month period.

3.. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
1st ~~Revised~~ Original Sheet No. 40
~~Canceling Original Sheet No. 40~~

LARGE POWER STANDBY SERVICE
Rate 37

AVAILABILITY:

This rate is applicable for power and lighting requirements of customers having their own generating facilities desiring standby power of 200 kilowatts or more through a permanent connection to be used in the event of failure of such generating facilities, or for use during the maintenance and overhaul of such facilities.

RATE:

Primary Service:

Basic Service Charge:	$300.00~~150.00~~ per month
Contract Demand Charge:	$15.64~~11.73~~ per Kw
Energy Charge:	1.131~~1.129~~¢ per Kwh

~~Power Supply Cost Adjustment:~~
~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Secondary Service:

Basic Service Charge:	$95.00~~66.00~~ per month
Contract Demand Charge:	$15.28~~12.20~~ per Kw
Energy Charge:	0.479~~0.478~~¢ per Kwh

~~Power Supply Cost~~ Adjustment Clauses:

~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~
Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 40
~~Canceling Original Sheet No. 40~~

LARGE POWER STANDBY SERVICE
Rate 37

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge plus Contract Demand Charge (Contract Demand minimum).

LARGE POWER STANDBY SERVICE
Rate 37

PAYMENT:

Bills 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 or any amendments or alterations thereto.

~~POWER SUPPLY COST ADJUSTMENT:~~

~~Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.~~

DETERMINATION OF CONTRACT DEMAND:

The demand in kilowatts for billing purposes shall be the greater of either the maximum 15-minute measured demand in the current month or the contract demand in kilowatts. Measured demand will be determined to the nearest one-tenth kilowatt. The Company will require the customer to contract for additional standby and supplementary capacity if the customer exceeds the contract demand in any one month. Such measured demand shall become the new contract demand commencing with the month in which measured and thereafter for the eleven succeeding months, after which the customer and Company will redetermine full service requirements

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

CONTRACT TERMS:

The customer agrees to contract for service under the Large Power Standby Service rate for a minimum period of one year. If the customer fails to continue service for the initial annual period, the customer will be billed for the difference

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

State of Wyoming
Electric Rate Schedule

LARGE POWER STANDBY SERVICE
Rate 37

between the customer's actual billing under Rate 37 and what would have been billed under Rate 39.

GENERAL TERMS AND CONDITIONS:

1. The customer will contract for capacity adequate to supply the entire electrical requirements for which the Company's service may be used. Contract demand will be no less than what the Company will be required to supply in case of customer equipment malfunction.
2. No customer may connect an independent source of power in parallel with the Company's system without prior written consent of the Company. Any customer desiring to generate in parallel shall execute a contract with the Company that contains terms and provisions regarding metering, billing, technical, and operating parameters for the customer's independent source of power.
3. The customer shall be subject to charges for interconnection costs, as defined in the Energy Sales Agreement.
4. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 43

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

AVAILABILITY:

In all communities served for power to customers having a demand of 500 Kw or more where at least 75 percent is available for interruption up to 100 hours annually. Electric energy for the interruptible load shall be supplied through a common customer meter used to serve the customer's total electrical load.

RATE:

Primary Service:

Basic Service Charge:	$300.00 per month
Demand Charge:	$16.14 per Kw of Billing Demand
Demand Response Credit:	$2.75 per Interruptible Kw of Interruptible Load
Energy Charge:	1.131¢ per Kwh

Secondary Service:

Basic Service Charge:	$95.00 per month
Demand Charge:	$15.78 per Kw of Billing Demand
Demand Response Credit:	$2.75 per Interruptible Kw of Interruptible Load
Energy Charge:	0.479¢ per Kwh

Adjustment Clauses:

Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced rate schedule for current rates:

1. Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
2. Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge plus the Demand Charge (500 Kw minimum).

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 43.1

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

PAYMENT:

Bills 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 or any amendments or alterations thereto.

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 500 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to Conditions of Service Rate 100, Section 700.

DETERMINATION OF INTERRUPTIBLE KW:

Interruptible Kw shall be the Billing Demand less the Baseline Non-Interruptible Load.

BASELINE NON-INTERRUPTIBLE LOAD:

Annually, customers must select a Baseline Non-Interruptible Load in Kw which shall not be subject to interruption. Customers must select a Baseline Non-Interruptible Load that results in at least 75% expected load being interrupted.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. The customer shall execute an electric service agreement with the Company which shall include a minimum term of service, the Baseline Non-Interruptible Load, and any additional customer costs incurred by Company for facilities, such as substations, electric lines, meters, switching devices, and circuit breakers that are necessary to provide service under this rate schedule.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 43.2

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

a. Electric service agreements shall also include contact information, method(s) of communication to initiate demand response event(s), and test procedures for calculating Baseline, Non-Interruptible Load.

2. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required electric service agreement. Enhancements and/or modifications to equipment may be required to ensure equipment functionality and/or communication with the Company's fixed network facilities. Such enhancements and/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.

3. Customer will be required to interrupt service within 30 minutes of the Company's notification to interrupt service unless agreed otherwise by the parties.

4. The penalty for non-performance by customer in response to a Company request to interrupt will be $12.00 per Kw applicable to the Interruptible Kw specified in the electric service agreement with the Company. After a second failure to perform within a 12-month period, the customer may be moved to the otherwise applicable rate at the Company's discretion.

5. The Company may request a summer and winter performance test each year, lasting up to one hour in length, to test the customer's interruption capability and Baseline Non-Interruptible Load. Scheduled performance tests shall not count against the 100 hour limit

6. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

7. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
1st ~~Revised~~ Original Sheet No. 45
~~Canceling Original Sheet No. 45~~

LARGE GENERAL ELECTRIC SERVICE
Rate 39

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 kilowatts of billing demand, except customers covered by special contracts. The customer's wiring must be so arranged that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

RATE:

Primary Service:

Basic Service Charge:	$300.00~~150.00~~ per month
Demand Charge:	$16.14~~11.23~~ per Kw of billing demand
Energy Charge:	1.131~~1.129~~¢ per Kwh

~~Power Supply Cost Adjustment:~~
~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Secondary Service:

Basic Service Charge:	$95.00~~66.00~~ per month
Demand Charge:	$15.78~~11.70~~ per Kw of billing demand
Energy Charge:	0.479~~0.478~~¢ per Kwh

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
1st ~~Revised~~ Original Sheet No. 45
~~Canceling Original Sheet No. 45~~

LARGE GENERAL ELECTRIC SERVICE
Rate 39

~~Power Supply Cost~~ Adjustment Clauses:

~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge plus Demand Charge.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~46~~45.1

LARGE GENERAL ELECTRIC SERVICE
Rate 39

PAYMENT:

Bills 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 or any amendments or alterations thereto.

~~POWER SUPPLY COST ADJUSTMENT:~~

~~Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.~~

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15-minute measured demand in the current month or 50 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to Conditions of Service Rate 100, Section 700.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. Architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~47~~45.2

LARGE GENERAL ELECTRIC SERVICE
Rate 39

2. The primary service rate is applicable to customers that own their own transformers, related equipment, and distribution facilities downstream of the meter, satisfactory to the Company so customers can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 50
~~Canceling Original Sheet No. 50~~

~~MUNICIPAL~~PUBLIC ~~-~~ LIGHTING SERVICE
Rate 41

AVAILABILITY:

For the lighting of streets, alleys, and other road right of ways in ~~Company-owned and municipally-owned street lighting systems in~~ Sheridan, Dayton and Ranchester, Wyoming~~.~~ ~~for street lighting purposes including streets, alleys and other public grounds.~~ Service will be provided all night every night with a minimum service requirement of 4,000 hours annually.

RATE:

Energy Charge: 7.230~~5.507~~¢ per Kwh for all energy used

~~Power Supply Cost~~ Adjustment Clauses: ~~Subject to change on an annual basis – see Rate Summary Sheet or Sheet No. 58 for current rate~~

Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

Facilities Charge per unit per month:
Applicable to lighting facilities owned, installed, and maintained by the Company.

LED, Overhead Conductor, Distribution Pole	$ 6.70
LED, Overhead Conductor, Street Light Pole	$12.80
LED, Underground Conductor, Distribution Pole	$ 8.60
LED, Underground Conductor, Street Light Pole	$14.70
Wood Pole	$ 7.00

PAYMENT:

Bills 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 or any amendments or alterations thereto.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 50
~~Canceling Original Sheet No. 50~~

~~MUNICIPAL~~PUBLIC ~~-~~ LIGHTING SERVICE
Rate 41

~~POWER SUPPLY COST ADJUSTMENT:~~

~~Service under this rate schedule is subject to an adjustment for the cost of fuel and purchased power in accordance with the Power Supply Cost Adjustment (PSCA) Rate 50, or any amendments or alterations thereto.~~

GENERAL TERMS AND CONDITIONS:

1. When service is not metered, the bill shall be computed on a~~n annual~~ daily basis, utilizing the minimum service requirement of 4,000 hours annually, and ~~one-twelfth shall be payable each month~~billed monthly to the customer.

2. In Company-owned street lighting systems, a monthly rental charge shall be rendered in addition to the energy charge. The customer should consult with the Company for such costs.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~51~~50.1

~~MUNICIPAL~~PUBLIC ~~-~~ LIGHTING SERVICE
Rate 41

3. ~~In~~For Company-owned ~~street~~ public lighting systems, the Company will maintain the facilities and change the light bulbs when notified by the ~~municipality~~ customer that they are burned out except when the facilities are damaged or destroyed by vandalism, malicious mischief by third parties, or willful negligence on the part of ~~employees of the municipality~~ the customer. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the ~~municipality~~ customer for the cost of repair and replacement.

   The Company will convert mercury vapor light units to high pressure sodium upon failure of existing mercury vapor units.

4. In ~~municipally~~customer-owned street lighting systems, an additional charge will be made to cover lamp replacements, materials and labor whenever such services are supplied by the Company.

~~5. Service will be provided all night every night in the year with a minimum service requirement of 4,000 hours annually, and must be covered by written contract.~~

5~~6~~. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 55
~~Canceling Original Sheet No. 55~~

POWER SUPPLY COST ADJUSTMENT
Rate 50

1. APPLICABILITY:
   This rate schedule constitutes a Power Supply Cost Adjustment (PSCA) provision and specifies the procedure to be utilized to adjust the rates for fuel and purchased power sold under Montana-Dakota's rate schedules in order to reflect the recovery (refund) of the Power Supply Balancing Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:
   The effective date of the PSCA shall be service rendered on and after May 1 each year unless the Wyoming Public Service Commission (Commission) shall otherwise order. The Company will file an application with the Commission to implement the PSCA rate on an interim basis and, if approved by the Commission, the PSCA rate shall continue until a final order is issued by the Commission establishing an effective PSCA rate.

3. POWER SUPPLY COST ADJUSTMENT:
   a. The annual PSCA shall be calculated separately for primary service and secondary service and reflect changes in Montana-Dakota's cost of power supply as compared to the base cost of power supply established in a general rate case for each class.

   b. The cost of power supply shall be the sum of the approved costs incurred in obtaining fuel and purchased power supply for use by all customers served under retail sales rate schedules for the twelve month period ending December 31 each year.

   c. The cost of power supply shall include the following costs for fuel and purchased power supply:

      1. Fuel and fuel handling costs recorded in Account No. 501 and reagent costs recorded in Account 502;
      2. Demand, energy, ancillary services and transmission charges recorded in Account 555; and
      3. Regional Marketing Administration expenses recorded in Account 575; and
      4. The cost of new or existing governmental impositions for electric generation plant emissions, including but not limited to SO_2 allowances, carbon taxes and/or carbon allowances and other governmental initiatives related to electric generation plant emissions. Prior to

including any new governmental impositions in the PSCA, the Company will receive approval from the Commission.

d. The base cost of power supply shall consist of all power supply costs established in a general rate case for primary and secondary service stated on a Kwh basis. The base cost of power supply established in Docket No. 20004-___~~117~~-ER-25~~16~~ is as follows:

Base Cost of Power Supply Expense	Primary	Secondary
Fuel	1.056~~0.982~~¢	1.067~~0.991~~¢
Purchased Power	2.846~~2.157~~¢	3.355~~2.423~~¢
Total	3.902~~3.139~~¢	4.422~~3.414~~¢

e. The calculation of the power supply cost adjustment is shown on Sheet No. 55.4~~59~~.

4. POWER SUPPLY BALANCING ACCOUNT:
   a. Items to be included in the Power Supply Balancing Account are:
      1. Amounts under recovered or over recovered for fuel;
      2. Amounts under recovered or over recovered for purchased power supplies each month;
      3. Refunds received with respect to fuel and purchased power supply shall be credited to the Power Supply Balancing Account; and
      4. Interest on the net over or under collected balance in accordance with Subsection 4.b.4.

   b. The amount to be included in the Power Supply Balancing Account in order to reflect the items specified in Subsection 4.a.1-4 shall be calculated as follows:
      1. Montana-Dakota shall first determine each month the unit cost for that month's fuel cost and purchased power costs by PSCA class:

a. Fuel costs shall be allocated to each class based on sales volumes for the month adjusted for the applicable loss factor from the most recently approved general rate case; and

b. Purchased power energy shall be allocated to each class based on sales volumes for the month adjusted for the applicable loss factor from the most recently approved general rate case. Purchased power demand and transmission charges shall be allocated to each class based on the average and excess demand factor that will be updated annually.

2. Montana-Dakota shall then subtract from each month's unit cost (fuel and purchased power) the total cost in rates as set forth in Subsection 6:
   a. For fuel, the difference (which may be positive or negative) shall be multiplied by 85 percent and by the Kwh sold during that month under each applicable rate schedule. The resulting amounts shall be reflected in the Balancing Account (Account 182.3) for primary and secondary service; and
   b. For purchased power, the difference (which may be positive or negative) shall be multiplied by 95 percent and by the Kwh sold during that month under each applicable rate schedule. The resulting amounts shall be reflected in the Balancing Account for primary and secondary service.

3. The amounts in the Power Supply Balancing Account shall be decreased each month by an amount determined by multiplying the currently effective Surcharge Adjustment included in rates for that month by the Kwh sales during that month under each rate schedule. The amount in the account shall be increased in the event the adjustment is a negative amount.

4. The balance in Account 182.3, to which interest will apply, will be the balance at the end of the immediately preceding month. Interest shall be applied to the net over or under collected balance at one-twelfth of the

Commission's Authorized Interest Rate specified in Chapter 1, Section ~~2~~3(a)(xv~~i~~i) of the Commission's Rules and recorded in Account 182.3.

The amount amortized each month shall be applied pro rata between the amounts in the Power Supply Balancing Account specified in Subsection 4.a.1. and 2. and the amount related to carrying charges specified in Subsection 4.a.

5. TIME AND MANNER OF FILING:
   a. Each application by Montana-Dakota shall be made by means of revised PSCA and rate schedule tariff sheets identifying the amounts of the adjustments and the resulting currently effective PSCA rates.

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

   c. The application shall be made 60 days prior to the implementation date of May 1 each year.

6. POWER SUPPLY COST ADJUSTMENT:
   The total power supply cost equals 3.902~~4.546~~¢ per Kwh for the Primary Service PSCA rate class and 4.422~~5.127~~¢ per Kwh for the Secondary Service PSCA rate class. The currently effective PSCA applied to each rate schedule and shown separately on the consumer bill is:

	Primary	Secondary
Base Cost of Power Supply	3.902~~3.139~~¢	4.422~~3.414~~¢
Power Supply Cost Adjustment	0.000~~1.151~~	0.000~~1.259~~
Power Supply Balancing Account Adjustment	0.000~~0.256~~	0.000 ~~0.454~~
Total PSCA	3.902~~4.546~~¢	4.422~~5.127~~¢

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~7th Revised~~ Original Sheet No. ~~59~~55.4
~~Canceling 6th Revised Sheet No. 59~~

POWER SUPPLY COST ADJUSTMENT
Rate 50

	Total	Primary	Secondary
Fuel			
501.1 Fuel	$2,362,294	$201,429	$2,160,865
501.4 Fuel Handling	209,716	17,882	191,834
502. Reagents	549,830	46,883	502,947
Total Fuel	$3,121,840	$266,194	$2,855,646
Kwh Sales	292,769,653	25,217,920	267,551,733
Cost per Kwh		$0.01056	$0.01067
Base Fuel Cost		0.01056	0.01067
Difference from Base		$0.000000	$0.000000
Total Change from Base	$0	$0	$0
Amount to be recovered (refunded) from customers (85%)		$0	$0
Purchased Power			
555.1 Energy	$4,176,744	$356,144	$3,820,600
555.6 Capacity	2,826,007	185,168	2,640,839
555.6 Transmission	2,692,378	176,412	2,515,966
Purchased Power	$9,695,129	$717,724	$8,977,405
Kwh Sales	292,769,653	25,217,920	267,551,733
Cost per Kwh		$0.02846	$0.03355
Base Cost of Purchased Power		0.02846	0.03355
Difference from Base		$0.00000	$0.00000
Total Change from Base	$0	$0	$0
Amount to be recovered (refunded) from customers (95%)		$0	$0
Power Suppy Cost Adjustment			
Balance @ 12/31/__		$0	$0
Under (Over) Recovery			
Fuel		$0	$0
Purchased Power		0	0
Net		$0	$0
Amortization			
Interest			
Balancing Account balance @ 12/31/__		$0	$0
Estimated amortization Jan-April			
Net Balance		$0	$0
Projected Kwh sales		25,217,920	267,551,733
PSCA Adjustment		$0.0000	$0.0000
Base PSCA		$0.03902	$0.04422
PSCA Adjustment		0.00000	0.00000
Total PSCA		$0.03902	$0.04422

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~7th Revised~~ Original Sheet No. ~~59~~55.4
~~Canceling 6th Revised Sheet No. 59~~

POWER SUPPLY COST ADJUSTMENT
Rate 50

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - WYOMING
POWER SUPPLY COST ADJUSTMENT
TARIFF CALCULATION

	Total	Primary	Secondary
Fuel			
501.1 Fuel	$2,381,166.52	$203,216.92	$2,177,949.60
501.4 Fuel Handling	573.13	48.91	524.22
502.4 Reagents	420,150.55	35,857.09	384,293.46
Total Fuel	$2,801,890.20	$239,122.92	$2,562,767.28
kWh Sales	292,769,653	25,217,920	267,551,733
Cost per kWh		$0.00948	$0.00958
Base Cost of Fuel		0.00982	0.00991
Difference from Base		($0.00034)	($0.00033)
Total Change from Base	($96,866.16)	($8,574.09)	($88,292.07)
Amount to be recovered/(refunded) from customers (85%)		($7,287.98)	($75,048.26)
Purchased Power			
555.1 & 575 Energy	$5,154,621.70	$439,913.10	$4,714,708.60
555.6 Capacity	2,707,479.10	193,803.06	2,513,676.04
555.6 Transmission	2,921,019.58	209,088.42	2,711,931.16
Purchased Power	$10,783,120.38	$842,804.58	$9,940,315.80
kWh Sales	292,769,653	25,217,920	267,551,733
Cost per kWh		$0.03342	$0.03715
Base Cost of Purchased Power		0.02157	0.02423
Difference from Base		$0.01185	$0.01292
Total Change from Base	$3,755,600.74	$298,832.35	$3,456,768.39
Amount to be recovered/(refunded) from customers (95%)		$283,890.73	$3,283,929.97
Power Supply Balancing Account Adjustment			
Balance at 12/31/23		($6,127.38)	$673,055.26
(Over)/Under Recovery			
Fuel		($7,824.33)	($74,785.02)
Purchased Power		269,579.05	3,298,992.75
Less: Current Power Supply Cost Adjustment		166,228.91	1,845,193.21
Net		$95,525.81	$1,379,014.52
Amortization		46,698.06	926,285.41
Interest		(3,242.33)	13,496.79
Balance at 12/31/24		$39,458.04	$1,139,281.16
Estimated Amortization January-April 2025		($26,920.94)	($102,641.04)
Net Balance		$66,378.98	$1,241,922.20
Projected kWh Sales		25,976,000	273,405,000
Power Supply Cost Balancing Account Adjustment		$0.00256	$0.00454
Base Cost of Power Supply		$0.03139	$0.03414
Power Supply Cost Adjustment		0.01151	0.01259
Power Supply Cost Balancing Account Adjustment		0.00256	0.00454
Total PSCA		$0.04546	$0.05127

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 60

RELIABILITY AND SAFETY INFRASTRUCTURE RIDER
Rate 55

APPLICABILITY:

This rate schedule provides a Reliability and Safety Infrastructure Rider (RSIR) recovery mechanism and specifies the procedure utilized to recover the revenue requirement associated with projects designed to improve the reliability and safety of the Company's electric infrastructure in Wyoming. RSIR costs recovered under the rider have been approved by the Commission and may include, but are not limited to, new or modified transmission-level projects specific to the improvement of power delivery and reliability to customers, replacement of pre-1985 underground distribution cables, and upgrades necessary for wildfire mitigation. Costs included in the rider are not reflected in the rates established in the most recent general rate case.

RELIABILITY AND SAFETY INFRASTRUCTURE RIDER:

1. The RSIR shall be calculated annually reflecting forecasted costs through year end of the filing year and through November of the following year.

2. The rider shall include a return requirement on the capital investment based on the rate of return authorized in the Company's most recent general electric rate case, in addition to operation and maintenance expenses, depreciation expense, and ad valorem tax expense associated with the eligible projects and a true-up of the previous year's rate.

3. A true-up will reflect any over- or under collection of revenue under the RSIR based on actual expenditures from the preceding twelve month recovery period. Interest shall be applied to the net over or under collection at one-twelfth of the Commission's authorized interest rate specified in accordance with Chapter 1, Section 3(a)(xvii) of the Commission's Rules.

4. The resulting revenue requirement shall be divided by the Total Revenue excluding the Power Supply Cost Adjustment revenue from Montana-Dakota's most recent general electric rate case to determine a percentage adder rate applicable to all rate schedules.

5. The percentage adder shall be applied to the dollars billed under the Basic Service Charges, Energy Charges, and Demand Charges of each rate schedule and identified as its own line on customers' bills.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 60.1

RELIABILITY AND SAFETY INFRASTRUCTURE RIDER
Rate 55

6. When Montana-Dakota files its next general rate case, all project costs shall be removed from the RSIR and included in base rates. Only the true-up component (remaining rider balance) shall remain for recovery through the RSIR to be either collected or returned to customers over a subsequent period.

TIME AND MANNER OF FILING:

1. Each application by Montana-Dakota shall be made by means of a revised RSIR rate and tariff sheet reflecting updated project costs and true-up and the resulting rates.

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

3. The application shall be made 60 days prior to the implementation date of December 1 each year.

RSIR RATE: 0.00%

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~7th Revised~~ Original Sheet No. 70
~~Canceling 6th Revised Sheet No. 70~~

PARALLEL GENERATION
Rate 57

AVAILABILITY:

Available to (1) any single or three-phase electric service customer who generates electrical energy in excess of their total energy requirements and who has received qualifying status as a cogenerator or small power producer under Section 201 of the Public Utility Regulatory Policies Act of 1978, defined herein as Parallel Generation Customer, or (2) where the customer's intent is to primarily offset part or all of the customer's own electrical requirements, but whose generating facility exceeds the 25 Kw maximum allowed under Net Metering Rate 58, defined herein as Partial Requirements Customer (qualifying facilities).

RATE:

Service provided to such customers by the Company shall be billed at the appropriate rate, by class of customers (i.e., residential, commercial, etc.) that is currently on file with the Commission. Customers under this rate schedule will not be net metered.

Minimum Bill: Basic Service Charge.

Rates may be updated annually, in correlation with the Company's annual Power Supply Cost Adjustment filing.

Partial Requirements Customer:

Basic Service Charge:*	
Single Phase:	$3.30 per month
Three Phase:	$9.34 per month
Energy Payment:	3.448¢ per Kwh Received

Parallel Generation Customer:

(1) For generating facilities rated at 100 Kw or Less

Basic Service Charge:*	
Single Phase:	$13.68 per month
Three Phase:	$17.25 per month
Energy Payment:	3.448¢ per Kwh Received
Capacity Payment:	$8.29 per Kw Received per month

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

State of Wyoming
Electric Rate Schedule

PARALLEL GENERATION
Rate 57

*The Basic Service Charge under this rate schedule is subject to the Reliability and Safey Infrastructure Rider Rate 55 (Sheet No. 60).

Capacity payments will be made only to those qualifying facilities that actually contribute to a capacity savings to the Company by a reduction in the demand charges paid by the Company to Black Hills Power, Inc. under the terms of the contract between the Company and Black Hills Power, Inc. regarding the determination of the billing demand. The kilowatts used for determining any capacity payment by the Company shall be the kilowatts supplied by the qualifying facility at the time of the Company's monthly system peak demand.

(2) For generating facilities rated at 101 Kw and Greater

The Company will enter into individual agreements.

GENERAL TERMS AND CONDITIONS:

1. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

2. The customer shall, with prior written consent of the Company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.

3. Any changes made to the customer's generating facility that increases the capacity, included in the customer's Interconnection Agreement, must first be approved by Montana-Dakota prior to installation to ensure the continued safe and reliable operation of the Company's electric system. If the Company is not contacted, the Company reserves the right to disconnect the facility until the issue is resolved.

4. The foregoing schedule is subject to Rate 59 and Rates 100 and 104. Any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
~~1st Revised~~ Original Sheet No. 72
~~Canceling Original Sheet No. 72~~

NET METERING SERVICE
Rate 58

AVAILABILITY:

Available to any customer that owns and operates a solar, wind, biomass or hydroelectric generating facility with a capacity of not more than 25 Kw that is located on the customer's premises and that is intended primarily to offset part or all of the customer's own electrical requirements. The generating facility must be interconnected and operated in parallel with the Company's existing transmission and distribution facilities. This service is offered in compliance with Wyoming Statutes §37-16-101 to 104.

APPLICABLITY:

Net Metering means measuring the difference between the electricity supplied by the Company and electricity generated by an eligible customer-generator and fed back to the electric grid over the applicable billing period.

RATE:

Basic Service Charge: The Basic Service Charge per the applicable standard service rate.

Energy Charge: If the energy supplied by the Company exceeds the customer generated energy, the energy charge (including the PSCA) per Kwh under the otherwise applicable standard service tariff shall be applied to the positive energy balance and charged to the customer.

If the energy supplied by the customer generator exceeds the amount of energy supplied by the Company, the net Kwh shall be credited to the customer's next monthly bill.

GENERAL TERMS AND CONDITIONS:

1. At the beginning of each calendar year, any Kwh credit balance accumulated during the previous year shall be purchased by the Company at the currently effective avoided cost rate (energy payment) applicable under Parallel Generation Rate 57.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
1~~st Revised~~ Original Sheet No. ~~73~~72.1
~~Canceling Original Sheet No. 73~~

NET METERING SERVICE
Rate 58

2. The customer is responsible for all costs associated with its facility and is also responsible for all costs related to any modifications to the facility that may be required by the Company for purposes of safety and reliability.

3. A Net Metering facility shall meet all applicable safety and performance standards established by the National Electrical Code.

4. The customer is responsible, at their expense, for providing lockable switch equipment capable of isolating the net metering facility from the Company's system. Such equipment shall be approved by the Company and shall be accessible by the Company at all times.

5. A meter shall be installed between the parties to measure the flow of energy in each direction between the customer and Montana-Dakota. The customer shall be responsible for all expenses involved in purchasing and installing facilities necessary for the meter installation.

6. The customer shall enter into an Interconnection Agreement for Net Metering Service.

7. Any changes made to the customer's generating facility that increases the capacity, included in the customer's Interconnection Agreement, must first be approved by Montana-Dakota prior to installation to ensure the continued safe and reliable operation of the Company's electric system. If the Company is not contacted, the Company reserves the right to disconnect the facility until the issue is resolved.

   a. If the changes cause the generating facility's capacity to exceed the 25 Kw maximum allowed for under this rate schedule, the customer must enter into a new Interconnection Agreement under Parallel Generation Rate 57. Absent a new Interconnection Agreement, the Company reserves the right to disconnect the facility until the issue is resolved.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~74~~72.2

NET METERING SERVICE
Rate 58

8. The foregoing schedule is subject to Rate 59 and Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. 80

PARALLEL GENERATION GENERAL RULES
Rate 59

GENERAL RULES FOR PARALLEL GENERATION:

1. The interconnection between the utility and the qualifying facility will be limited to the service voltage and phases available at the qualifying facility. If different voltages or phases are required, the necessary changes will be provided by the qualifying facility.

2. The power factor and frequency of the qualifying facility shall be such as to not adversely affect the utility system. If corrective devices are required, they will be provided by the qualifying facility.

3. Fault protection equipment shall be provided by the qualifying facility. The utility and qualifying facility shall coordinate protective devices in order to limit damage to each system.

4. The qualifying facility's interconnection shall meet the requirements of local, state and federal codes.

5. The owner of the qualifying facility shall submit equipment specifications as requested by the utility prior to owner's installation of such equipment to assure compatibility and coordination with the utility system.

6. The owner of a qualifying facility will be requested to curtail, interrupt or reduce deliveries of electric energy, in order that the utility may construct, install, maintain, repair, replace, remove or inspect any of its equipment or any part of its system, or if it determines that curtailment, interruption or reduction of delivery is necessary because of safety, emergencies, forced outages or operating conditions on its system. Except in case of emergency, in order to minimize operating problems, the utility and qualifying facility shall give the other reasonable prior notice of any curtailment, interruption or reduction of delivery and its probable duration.

7. The Company reserves the right for periodic inspection of safety devices which are part of the interconnection. This would not affect the

responsibility of the qualifying facility to assure the operating safety of the equipment on its side of the interconnection point.

8. The Company reserves the right to disconnect any facility that has interconnected without utility authorization.

9. The Company has the right to disconnect and lock-out a qualifying facility's generating equipment with due notice whenever it has been determined that harmonics are being produced or other factors are present which would interfere with communications or otherwise cause degradation of service to other customers. If, in the judgment of the utility, an unsafe condition is created on the utility system by the operation of the qualifying facility, the utility shall have the right to disconnect the facility until the cause of such condition is eliminated.

10. In the event of a utility system outage or interruption of service, a qualifying facility's generator shall be capable of automatically disconnecting itself to prevent the utility's line from being energized. Also, a qualifying facility's system shall not be capable of energizing the utility's line when that line is deenergized.

11. A manually operated generator disconnect switch, provided by the owner of a qualifying facility, shall be accessible to utility personnel at all times. Such a switch would be used whether or not the owner is present to remove the qualifying facility's generator from the line in an emergency situation as determined by utility system conditions.

12. The owner of a qualifying facility shall maintain operating communications with the utility for facilities with a capacity of more than 100 Kw or as requested. Operating communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances and load reports.

13. All necessary rights-of-way and easements to install, operate, maintain, replace and remove utility facilities, including adequate access rights, are to be furnished by the owner of the qualifying facility on owner's property.

14. The metering shall be adequate to measure energy, or energy and capacity, from the qualifying facility to the utility, from the utility to the qualifying facility, and, if necessary, adequate to determine the time at which energy is transferred from one party to another.

15. Interconnection costs shall be on an actual cost basis for all costs that are in excess of the costs that the utility would have incurred if it had not engaged in interconnected operations, but instead generated or purchased the same amount of energy or capacity. The owner of a qualifying facility is allowed up to one year to reimburse the utility for these costs.

16. Where no changes to the utility system are necessary except for installing additional metering, an average interconnection fee for qualifying facilities of 100 Kw or less shall apply.

17. The owner of a qualifying facility will indemnify and hold the utility harmless from all loss on account of injury, death or damage to property caused by the qualifying facility unless the injury, death or damage is the direct result of the negligence of the utility.

18. Qualifying facilities shall be required to execute a contract that specifies a one-year minimum term and describes the responsibilities, liabilities, ownership of equipment, and location.

19. The owner of a qualifying facility shall obtain and maintain general liability insurance in the amount of $500,000 for each occurrence or as determined by the Wyoming Public Service Commission.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. 90

~~**TABLE OF CONTENTS**~~
CONDITIONS OF SERVICE Rate 100

TABLE OF CONTENTS

TABLE OF CONTENTS

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

State of Wyoming
Electric Rate Schedule

TABLE OF CONTENTS

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

State of Wyoming
Electric Rate Schedule

TABLE OF CONTENTS

TABLE OF CONTENTS

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

State of Wyoming
Electric Rate Schedule

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 generally 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 Regulatory Commissions as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. DEFINITIONS:

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

APPLICANT - A customer requesting Company to provide service.

COMMISSION AND COMMISSIONER - The Public Service Commission of Wyoming or a member thereof respectively.

COMPANY - Montana-Dakota Utilities Co.

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

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

DELIVERY POINT - The point where the Company's facilities join those of the customer.

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

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE - A customer desiring electric service must submit an application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of the customer desiring the service. Any customer may be required to make a deposit as required by the Company in accordance with §V.4. The Company may refuse service or discontinue service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any customer who uses electric service 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 electric service until notified by the customer to discontinue the service. The customer will be responsible for payment of all service furnished through the date of discontinuance.

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

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

4. RELOCATED FACILITIES – Where Company facilities are located on or adjacent to a customer's premises and where there is an encroachment(s) to electric facilities caused by the customer; said customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

5. NOTIFICATION OF UNSAFE CONDITIONS – The customer shall immediately notify the Company of any unsafe conditions associated with the Company's electric facilities at the customer's premises.

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

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

IV. LIABILITY:

1. CONTINUITY OF SERVICE – The Company's electric system is unusually widespread and has many interconnections with sources of power other than its own generating stations and it is subject to exposure by storms and other factors not under its control. The Company employs the latest developments in equipment and methods of operation for the purpose of maintaining adequate service. The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and

uninterrupted supply of electric service and will not be liable for any loss, injury, death or damage resulting from or caused by the interruption of the same.

2. CUSTOMER'S EQUIPMENT - Neither by inspection or rejection, nor in any other way does the Company give any warranty, expressed or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by the customer, leased by the customer from third parties or used on the customer's premises. It is the obligation of the customer to consult with the Company regarding available maximum fault current and to provide such protection devices as may be necessary to safeguard the equipment and installation from interruptions, variation in voltage and frequency, single-phase energization of three-phase lines, reversal of phase rotation or other abnormal conditions. (Refer to Paragraph 710)

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 electricity or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

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

5. FORCE MAJEURE - In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of

any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or Company, acts of public enemies 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 electric lines, animal interference, sudden partial or sudden entire failure of electric transmission or supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses, or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain, and operate any facilities required

for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

V. GENERAL TERMS AND CONDITIONS:

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

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

3. ELECTRIC SERVICE AVAILABILITY - Residential Electric Service is available to any residential customer for domestic purposes only. All normal sized equipment used for domestic lighting, heating, cooking and power, and used strictly for household purposes, may be supplied through one meter.

   a. Residential service is defined as service for domestic general household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments and mobile homes (this is not an all-inclusive list). In addition, auxiliary buildings on the same premises as the living quarters, used for residential purposes, may be served on the residential rate.

   Motors and other equipment which interfere with service to neighboring customers, all motors larger than 5 horsepower and

temporary or seasonal loads totaling more than 25 kilowatts (Kw) will not be permitted on the Residential Electric Service Rate without prior Company approval.

Only single phase service is available under the Residential Electric Service Rate.

b. Three phase service shall be served under the appropriate General Electric Service Rate.

c. General Electric Service is defined as service provided to nonresidential services, such as 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 parlors, 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).

d. If separate metering is not practical for premises that is using electricity for both residential purposes and for conducting business (or for nonresidential purposes), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or General) applicable to the type of service which constitutes more than 50% of the total connected load.

e. These rules will not change the classification of existing customers who were served electricity prior to October 1, 1988 except in the event of a different customer taking responsibility for the account.

f. Other classes of service furnished by the Company shall be defined in applicable rate schedules or in rules and regulations

pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed on the appropriate General Electric Service Rate.

4. CUSTOMER DEPOSITS - The Company may require a deposit from an applicant for electric service (applicant) or an existing customer in accordance with Chapter 3, Section 7 of the Wyoming Public Service Commission's Rules:

The Company may require a deposit to guarantee payment for each service. This deposit shall not be considered as an advance payment of bills but shall be held as security for payment of service rendered. The Company may refuse service to an applicant or discontinue service to a customer for failure to comply with customer deposit requirements. The Company shall apply the policies governing customer deposits uniformly.

a. The Company may require a deposit if:

i. A prior service account with the Company remains unpaid and undisputed at the time of application for service;

ii. Service from the Company has been discontinued for:
A. Nonpayment of any undisputed delinquent bill;

B. Failure to reimburse the Company for damages due to the customer's negligent or intentional acts; or

C. Acquisition, diversion or use of service without the authorization of or knowledge by the Company;

iii. Information provided upon application for service is materially false or a misrepresentation;

iv. The application is for initial service with the Company or the applicant did not have service with the Company for a

period of at least 12 consecutive months during the past four years;

v. The applicant or non-residential customer is unable to pass an objective credit screen. In order to pass the objective credit screen, the applicant or non-residential customer must fulfill one or a combination of the following:

A. Received 12 consecutive months of service from the Company, with the undisputed portions of the 12 most recent bills paid in full when due;

B. Have a favorable credit rating with a third-party credit reporting agency; or

C. Receive a favorable credit rating from the Company's financial risk assessment tool.

vi. The request is for service at an address where a former customer with an undisputed delinquent bill for service still resides or conducts business;

vii. The applicant or the customer, has been brought within the jurisdiction of the bankruptcy court, or has had a receiver appointed in a state court proceeding, within the five-year period immediately preceding the request for service; or

viii. The Company has determined that it has a significant financial risk in continuing to provide service to a specific non-residential customer. The Company and the customer may attempt to reach a deposit agreement. If the Company and the customer are unable to reach an agreement, the Company shall file a confidential petition requesting expedited review and Commission approval prior to collecting the customer deposit. The petition shall contain the basis for the Company's determination, the amount of

deposit sought and sufficient information for the Commission to contact the customer.

b. The Company shall not require a deposit as a condition of new or continued utility service based upon any criterion not specifically authorized by the Wyoming Public Service Commission's Rules.

c. Unless otherwise ordered by the Commission, the required deposit shall not exceed the total amount of the customer's estimated bill for three months of highest use based on the premises' monthly bills during the immediate previous 12-month period. If billing information for the immediate previous 12-month period is not available, the deposit will be based on anticipated service characteristics and anticipated load.

d. The Company shall retain records showing:

   i. The name and address of each customer making the deposit;

   ii. The date and amount of the deposit; and

   iii. Each accounting transaction concerning the deposit.

e. The Company shall provide the customer a non-assignable receipt or other record of deposit, showing the date and amount received.

f. The Company shall calculate simple interest on deposits at the Commission Authorized Interest Rate described in Chapter 1, Section ~~2~~3 (a)(xvii) of the Wyoming Public Service Commission's Rules. Interest shall apply only to deposits held for at least six months, but shall accrue from the initial date of deposit through the date the deposit is returned to the customer.

g. The Company may accept a written guarantee from an acceptable guarantor in lieu of a deposit to pay a customer's bill. After the Company has verified the customer's identity, the customer shall agree to permit the Company to provide the customer's account information to the guarantor upon the customer's default.

h. Deposits and any unpaid interest earned on deposits shall be applied as a credit to the customer's bill, unless requested by the customer to be refunded, when:

i. The accrued interest equals or exceeds $10.00. The Company shall apply the credit at least annually;

ii. A residential customer has received 12 consecutive months of service, with no cause to discontinue service; and the customer's bills have been paid when due;

iii. A commercial or industrial customer has received 12 consecutive months of service, with no cause to discontinued service; the customer's bills have been paid when due; and the customer passes the Company's objective credit screen; or

iv. Service is discontinued. The Company shall not require the customer to provide the original receipt in order for the deposit to be returned. Any credit balance on the account after the deposit is applied shall be refunded to the customer. If the Company is unable to make the refund due to lack of knowledge of the customer's location, additional interest will not accrue after the service discontinuation date. The Company shall manage such deposits as unclaimed property as required by Wyoming law (W.S. § 34-24-109).

5. METERING AND MEASUREMENT

a. Company will meter the electric service 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.

b. Meter Testing

1) Company's Testing - The Company's ongoing meter testing program is set forth in Rate 115.

2) Customer's Request - Upon request of the customer for a test of the accuracy of the Company's meter used on the customer's premises, the following provisions shall apply:

a. If the meter has not been tested within 12 months, the Company shall perform the test within a reasonable time without charge to the customer. The Company shall notify the customer of the time when the Company will conduct the test so the customer or the customer's representative may be present.

b. If the meter has been tested within 12 months, the Company shall notify the customer of the cost to perform the test. The Company shall notify the customer of the time when the Company will conduct the test ~~so the customer or the customer's representative may be present.~~

c. The Company shall promptly advise the customer of the test results.

d. If a meter is found to be in non-compliance with the Company's approved meter testing program, the

Company shall refund the payment the customer advanced for the meter test and shall repair or replace the meter. The Company shall also adjust and refund to the customer the overpayment of preceding bills, in accordance with §V.6. No refund is required from the Company except to the customer last served by the meter prior to testing. If the Company has under collected, the customer shall pay the adjusted costs in accordance with §V.6.

e. The meter accuracy test charge amount is provided in §VI.1.~~e~~f.

6. BILLING ADJUSTMENTS

a. In accordance with Wyo. Stat. § 37-2-218, if the Company charged, collected or received any rate or rates in excess of the rates fixed in the Company's tariff, the Company shall immediately refund to the customer the difference between the rates fixed in the tariff and the rates charged, collected or received. This shall also apply to meter errors described in §V. 5.

b. If the Company undercharged a customer as a result of a meter or metering inaccuracy or other continuing problem under the Company's control, the Company may bill the customer in accordance with Wyo. Stat. § 37-2-222, for the amount of unmetered electricity rendered in the 183 days immediately prior to the date the Company remedies the meter inaccuracy. The typical time period over which the undercharge may be collected shall be 12 consecutive months. The customer may elect to pay over a shorter period, or the Company may allow repayment over a longer period. This shall also apply to meter errors described in §V.5.

7. LATE PAYMENT - Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to the percentage set forth in §VI.2. will be applied to any past due balance, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

8. RETURNED CHECK CHARGE - A charge as set forth in §VI.1.b will be collected by the Company for any check not honored by the customer's ~~bank~~ financial institution for any reason.

9. MANUAL METER READING CHARGE: A charge as set forth in §VI.1.c 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 a minimum period of one year.

10~~9~~. TAX CLAUSE

a. In addition to the charges provided for in the electric 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:

1. Any sales, use or excise taxes whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

2. Any payment under any electric franchise ordinance amounting to more than 1% annually of the gross electric revenue derived by the Company from electric business

within the corporate limits of the municipality, political subdivision, or other entity, imposing the payment.

3. The taxes imposed by the Sheridan Ordinance as adjusted for accounting and billing costs.

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

11~~10~~. UTILITY CUSTOMER SERVICES:

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

1. Fire Call

2. Investigate hazardous condition on customer premises.

3. No lights or power investigation.

4. Maintenance or repair of the following Company-owned equipment on the customer's premises:
   i. Meter
   ii. Overhead Service Line
   iii. Underground Service Line

b. The following service calls will be performed at no charge during the Company's normal business hours of 8:00 a.m. – 5:00 p.m. Monday through Friday local time:

1. A reconnection of service to an existing facility (cut-ins) or a discontinuation of service

2. Checking Voltage or Loads

3. Locating Radio, CB or Television Interference

4. High Bill Complaint

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

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

12~~11~~. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS - For service requested by customers after the Company's normal business hours defined in §V.1~~0~~1 and on Saturday, Sunday, or legal holidays, a charge will be made for labor at the overtime service rate set forth in §VI.1.~~f~~g. plus the cost of any required materials.

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.

13~~12~~. NOTICE TO DISCONTINUE ELECTRIC SERVICE - Customers desiring to have their electric service discontinued shall notify the Company during regular business hours, at least one business day before service is to be disconnected. Such notice shall be by letter, personal visit or telephone call to the Company's local business office, in communities in which an office is maintained. In other communities such notice shall be given to the Company's representative who services the community or to the nearest business office. Saturdays, Sundays and legal holidays are not considered business days.

14~~13~~. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMERS - A fee, as set forth in §VI.1.~~d~~e. will be collected for reconnecting electric service to any customer who has discontinued electric service at the same location during the preceding 12 month period, provided no other customer has taken service at the same location in the meantime.

15~~14~~. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS - All amounts billed for service are due by the due date on the bill and will be considered delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company in accordance with Chapter 3, Section 9 of the Wyoming Public Service Commission's Rules.

a. Discontinuation Notice - The Company may discontinue service by reason of nonpayment after issuing a disconnect notice and upon not less than 7 days' notice of proposed termination for residential customers and not less than 3 days' notice for nonresidential customers. The disconnect notice will be mailed or delivered to the account holder or by telephone after customer verification and mailed to any third party previously designated by the account holder. Additional notice may be provided electronically. The notice shall contain:

1. The name of the person whose account is delinquent and the service address to be discontinued;

2. The amount of the delinquent bill;

3. The effective date of the notice and the date on or after which service is to be discontinued;

4. The Company's specific address and telephone number for information regarding how to avoid service discontinuation;

5. The names of agencies or organizations that have notified the Company that they render assistance to eligible persons who are unable to pay their utility bills; and

6. A statement advising the customer how to contact the Commission if discontinuation is disputed.

b. Landlord Account Holders - When the Company is discontinuing service for nonpayment by a landlord, the Company shall post, mail, or deliver to each known tenant a written notice, excluding the dollar amount, informing the tenant only of the impending disconnection and advising each tenant it has 15 days to arrange directly for service, as permitted by the available facilities. The tenant shall not be held responsible for the landlord's delinquent utility billings. The Company will post the

notice at a central location on or in the rental building if all tenants cannot be identified.

c. The Company will notify the customer that, if prior to the initial date for the discontinuation of service, the customer provides the Company with written verification from a health care provider responsible for the care of customer or his/her co-habitants stating that their health or safety would be seriously endangered if service were discontinued, the Company shall extend the date for discontinuation set forth in the notice by 15 days (22 days total) to allow for bill payment.

d. The Company shall attempt to make actual contact with the customer either in person or by telephone, after the customer identity verification, before discontinuing service during the cold weather period of November 1 through April 30.

e. The Company shall also provide notice of discontinuation or account delinquency to a third party if the customer, or person acting for the customer, has requested ~~that~~ the Company do so after the customer identity ~~identification~~ verification. The Company shall advise the Customer that the right to request third-party notification does not create third-party liability for payment.

f. If the customer defaults, the Company shall provide the discontinuation notice to any guarantor and the customer simultaneously. The guarantor's service shall not be subject to discontinuation as a result of the customer's default.

g. The Company shall remove a guarantor when:

1. The customer has received 12 consecutive months of service with no cause for discontinuation, bills have been paid when due and the customer passes an objective credit screen

2. The guarantor has paid all amounts due for service through the date the Company received the request to terminate the guarantor agreement; or

3. An additional agreement with the Company is in place.

h. Reconnection After Nonpayment - To have service restored after discontinuation of service for nonpayment, a residential or a non-residential customer must first pay a charge for reconnection as set forth in §VI.1.~~c~~d, and must also pay the delinquent balance in full or execute a written deferred payment agreement, if eligible. The Company may also require a deposit to secure payment of future electric bills. See §V.4 Customer Deposits.

i. Discontinuation - The Company may discontinue service between 8:00 a.m. to 4:00 p.m., Monday through Thursday if not a legal holiday or the day preceding a legal holiday without further notice when:

1. The notification period has elapsed and the delinquent account has not been paid; or

2. Acceptable payment arrangements have not been made with the Company.

j. Service Extender – Service Extender provides a temporary alternative to discontinuing electric service for non-payment by extending a controlled level of service to the delinquent customer prior to service being discontinued. The minimum size Service Extender used for a Residential customer is 10 amps. Service Extenders shall not be applicable to a residence where the primary source of heating is electricity. If the Company choses to install a Service Extender, service may be

discontinued without further notification. Notification of the Service Extender shall be delivered to an adult or posted at the affected premises and shall include:

1. The customer's name;

2. Date the Service Extender was installed;

3. Customer operational instructions for the Service Extender;

4. Telephone number and address of the Company; and

5. Warning that service may be discontinued without further notification.

k. The Company shall assist persons who are unable to pay their electric service bills with determining available government assistance.

16~~15~~. PROHIBITIONS AGAINST SERVICE DISCONTINUATION – The Company shall not terminate service for bill nonpayment under the following conditions:

a. On a legal holiday as defined by Wyoming Statute §8-4-101, or the day before such a legal holiday;

b. During the period from December 24 through January 2, inclusive;

c. On any day in which the Company cannot reconnect service;

d. If the customer enters into an arrangement with the Company for payment of the delinquent billing over a reasonable time and the customer complies with payment arrangements;

e. If there are monies owed due to meter or other billing error, and the customer complies with payment arrangements;

f. At a previous address for a different class of service;

g. For nonutility services or appliance or merchandise provided by, or sold by, the Company to the customer;

h. If the customer is paying the electric service bills on time, even though a prior customer with an undisputed delinquent bill for service resides or conducts business at the same address;

i. If an electric service bill, or part of a bill, is legitimately in dispute, and if the customer duly pays the electric service bill, or bill portion, not in dispute;

j. If the temperature for the community closest to the customer's location is forecasted by the National Weather Service or other reputable source to be below 32°F in the impending 48 hours, or if conditions are otherwise especially dangerous to health, and the customer is:

1. A residential customer;

2. A non-residential customer providing service essential for the protection of public health, safety, or welfare; and:

3~~1~~. Unable to pay for service in accordance with the Company's billing requirements and is actively seeking government assistance or has exhausted such assistance; or

4~~2~~. Able to pay for service in installments; or

k. If the customer pays a bill on time for a specific service at a specific location, even though the customer is receiving another service that is subject to discontinuation for bill nonpayment.

17~~16~~. 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. For the use of electricity for any property or purpose other than that described in the application made for service.

b. For failure to maintain in good order service entrance facilities or equipment owned by the customer.

c. For use of equipment which adversely affects the Company's service to its other customers.

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

e. The Company may discontinue service for causes other than non-payment after issuing a disconnect notice in accordance with §V.14~~5.~~a. The discontinuance of service for causes other than non-payment shall occur on the days and during the hours stated in §V.14~~5.~~i.

f. 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.

g. The Company may discontinue service without advance notice for reasons of safety, health, cooperation with civil authorities, fraudulent use, tampering with or destroying Company facilities.

h. The Company may collect a reconnect fee as prescribed in §VI.1.~~c~~d. before restoring electric service which has been discontinued for the above causes.

18~~17~~. 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 Montana-Dakota Utilities Co. The bill shall be computed at the applicable rate, and the amount reduced by 33 1/3%.

19~~18~~. REFUSAL TO SERVE NEW CUSTOMERS OR EXPAND EXISTING SERVICE – A utility may refuse to provide, expand or materially change service to a requesting customer when:

a. The Company does not have adequate facilities to render the service requested and the customer is not willing to comply with the utility's line extension policy;

b. The requested service appears to be unsafe or likely to adversely affect service to another customer; or

c. The requesting customer is indebted to the Company for service previously rendered and satisfactory payment arrangements have not been made with the utility.

1. If indebtedness for service rendered at a former location is in dispute, the requesting customer shall be provided service at the new location upon complying with the Company's deposit requirements and paying the amount in dispute. Upon settlement of the disputed amount, any balance due the customer shall be refunded with accrued interest at the Commission Authorized Interest Rate described in Chapter 1, Section ~~2~~3(a)(~~XV~~xvii) of the Wyoming Public Service Commission Rules.

2. The Company shall not refuse service to a new customer because of debts of a previous customer at the same location.

3. The Company may refuse service due to unpaid line extension charges for facilities serving the location.

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

VI. MISCELLANEOUS CHARGES

	Amount or Reference
1. Service Charges	
a. Consumer deposits	Rate 100 §V.4.
b. Returned check	$30.00~~20.00~~
c. Manual Meter Reading Charge	$26.05
d~~c~~. Minimum reconnect charge after discontinuation of service for nonpayment or other causes	
- During normal business hours	$35.00~~20.00~~
- Removal of service extender	$35.00~~20.00~~
- After normal business hours	Minimum of $140.00
e~~d~~. Minimum reconnect charge applicable to seasonal or temporary customers	
- During normal business hours	
- Customers with non-demand meters	$35.00~~20.00~~
- Customers with demand meters	$70.00~~40.00~~
- After normal business hours	Minimum of $140.00
f~~e~~. Special test of meter at customer's request (see Rate 100 §V.5.b.2 as to when this charge is applicable)	
- Meter error more than ±2%	None
- Meter error within ±2% and meter was tested within the prior 12 months	Labor & materials Minimum of $40.00~~25.00~~
g~~f~~. Service request after normal business hours	Materials & labor Minimum of $140.00

~~h~~g. Electric extension policy Rate 104

		Per Month	Approx. Annual Percent
2.	Late Payment Charges (on unpaid balance)	1%	12%

SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:

Rate 104 - Electric Extension Policy
Rate 105 - Dark Sky Lighting Service
Rate 122 - AutoPay Plan
Rate 123 - Summary Billing Plan
Rate 125 - Balanced Billing Plan

VII. ELECTRIC SERVICE RULES:

Section 100 – GENERAL

101. Electrical Codes and Ordinances

The Electric Service Rules and Regulations contained herein are supplementary to and do not intentionally conflict with nor supersede the latest edition of the National Electrical Code, the National Electrical Safety Code, nor such state and municipal laws and ordinances that may be in effect in the areas in which the Company furnishes electric service, except that where the requirements of these Electric Service Rules and Regulations exceed those of such codes, laws, and ordinances, these Electric Service Rules and Regulations shall apply. Existing installations, including maintenance replacements, that currently comply with prior revisions of these rules and regulations, need not be modified to comply with these rules except as may be required for safety reasons.

102. Wiring Adequacy

Wiring codes provide minimum requirements for safety. Installation of wiring capacity greater than minimum code requirements is recommended to bring to the customer all the benefits of electric service and to protect building investment by minimizing obsolescence resulting from an inadequate wiring system.

CONDITIONS OF SERVICE Rate 100

103. Inspection of Wiring
Where permits and inspections covering customer's wiring and installation are required by local ordinance, it is mandatory that such requirements be fulfilled before the Company will make connections to the customer's installation. In locations where such inspections are not required by law or ordinance, an affidavit by the wiring contractor stating that the wiring has been done in compliance with the National Electrical Code will be acceptable.

104. Permits, Certificates, Affidavits
It is the responsibility of the customer to obtain all necessary permits, certificates of inspection or affidavits as required in Paragraph 103 above and to notify the Company promptly of any proposed alterations or additions to customer's load. Failure to comply with these requirements may result in delayed connection, interruption of service or damage to apparatus.

105. Consultation with the Company
105.1 The location, size and character of the customer's load and the current, voltage, frequency, phases, etc. which the Company has available at the customer's location will determine the type of service supplied to the customer.

105.2 Architects, engineers, contractors, electric dealers, wiremen and others must confer with local representatives of the Company to determine the type of service that will be available before designing or preparing specifications for new electrical installations or alterations to existing installations.

105.3 In all cases involving large installations and other cases where any doubt exists, full information as to the type of service available should be obtained from the Company.

106. Unauthorized Use of Service
106.1 Unauthorized use of service is defined as any deliberate interference that results in a loss of revenue to the Company. Violators are subject to prosecution.

106.2 Types of unauthorized use of service include, but are not limited to, the following:

(a) Bypass around meter.
(b) Meter reversed.

(c) Equipment connected ahead of meter.
(d) Tampering with meter that affects the accurate registration of electric usage.
(e) Electricity being used after service has been discontinued by the Company.

106.3 In the event that there has been unauthorized use of service, customer shall be charged for:
(a) All costs associated with investigation or surveillance;
(b) Estimated charge for non-metered electricity;
(c) All time to correct situation;
(d) Any damage to Company property.

106.4 A customer's service disconnected for unauthorized use of service shall be reconnected after the customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid any 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 equipment, costs incurred in the preparation of the bill, plus costs as outlined in Paragraph 106.3;
(d) Applicable reconnection fee;
(e) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with §V.4 and Chapter 3, Section 7 of the Wyoming Public Service Commission's Rules.

107. Unauthorized Attachments to Poles
107.1 The unauthorized attachment of any flags, banners, signs, clothes lines, antennas, etc. to Company poles is prohibited. The use of poles for placards or other advertising matter is forbidden. The Company will remove such unauthorized attachments without notice and may prosecute any such trespassers.

107.2 Customers are cautioned to locate antennas so that they are beyond falling distance from the Company's lines, either transmission or distribution. Antennas and lead-ins shall be located a safe distance from and shall never cross over or under the Company's lines or contact the Company's poles. The Company disclaims all responsibility where such equipment contacts the Company's lines, poles or equipment.

Section 200 - USE OF ELECTRIC SERVICE

201. Rate Schedules

Electric service will be billed under the rate schedule that applies to the class of service used. Rate schedules applicable to various classes of service may be obtained from the Company upon request.

202. Resale of Energy

The Company will not supply energy for resale except as expressly covered by special contract or where such provision is a part of the rate schedule.

203. Temporary Service

Temporary service is any service for construction work, carnivals, gravel pits, occasional lighting, etc., which is not expected to continue in use for a period long enough to justify the construction cost necessary for extending service. When temporary service is desired the customer shall, in addition to paying the scheduled rates, make deposit in advance in the amount of the Company's estimated cost of installing and furnishing such temporary service facilities together with the cost of disconnecting and removing same and the estimated billing to the customer for electric service. Final billing will reflect credit for the salvage value of materials used in providing the temporary service. Any deficiency in such advance payment shall be paid by the customer upon presentation of a bill by the Company. Any amount deposited in excess of final billing by the Company will be refunded to the customer.

204. Standby Service

Where electric service is supplied as standby to a customer's generating facilities or vice versa, the customer shall provide and install at the customer's expense a suitable double-throw switch or other device which will completely isolate the customer's power facilities from the Company's system. The service entrance shall be installed so that the

phase conductors will be totally isolated from the customer's wiring before the standby unit is put into operation.

205. Parallel Service
Parallel operation of the customer's generating equipment with the Company's system shall be permitted to the extent provided in other approved rates.

206. Transformer Installations on Customer's Premises
206.1 The Company will supply transformers to be installed on the customer's premises when requested by the customer and in accordance with the following paragraphs.

206.2 The customer shall agree to indemnify and save the Company harmless, except for willful default or neglect on the Company's part, from any loss, damage, expense or liability, incurred or arising from, or out of the installation, operation, maintenance, repair or removal of its transformers, cables, conductors, apparatus and all other Company property, material or equipment placed on the customer's premises.

206.3 Company's power or distribution transformers will not be installed in the customer's building.

206.4 The Company will furnish, own and maintain conventional oil filled transformers at no cost to the customer. However, where dry type transformers, transformers containing a nonflammable insulating coolant or oil filled transformers of special voltage or design are required they shall be owned, installed and maintained by the customer at the customer's expense.

206.5 Padmount transformers may be installed on customer's premises. The customer shall furnish a suitable concrete pad, conduit, ground rod and service conductors as noted in Figure 5. Where the customer has more than four parallel conductors, a cable junction enclosure and conduits to the transformer location may be required. The customer shall consult with the Company to determine when a cable junction enclosure is required.

206.6 Where the transformer is installed adjacent to an asphalt or concrete driveway, parking lot, or walkway, the customer shall provide conduit from the transformer location to a point beyond the driveway, parking lot, or walkway to accommodate the Company's

primary voltage cable. The customer shall provide barriers and clear zones to protect transformer from damage and to allow proper cooling and access to conductor compartments. The customer shall consult with the Company to determine the proper size conduit and protective barriers.

206.7 Refer to Figure 5 for additional information on transformer location.

Section 300 - ELECTRIC SERVICE AVAILABLE

301. Frequency

All service supplied by the Company is alternating current at a nominal frequency of 60 Hertz.

302. Secondary Voltages (See also Section 400.)

302.1 In general, the following classes of service are normally supplied:

Phase	Wires	Nominal Voltage	Nominal Service	
	1	3	120/240	Single Phase Lighting & Power
	3	4 Delta	120/240	Combined Light & Power*
	3	4 Wye	208 Grd Y/120	Combined Light & Power
	3	4 Wye	480 Grd Y/277	Combined Light & Power**
	3	4 Delta	240/480	Combined Light & Power*

*Overhead Primary
**Underground Primary

Note: The Company follows the provisions of ANSI C84.1; latest revision, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

302.2 Only one class of service voltage is provided to a single customer location.

302.3 Service at other voltages may be made available for approved loads upon special application to the Company. Supplying such service may require special construction and equipment by the customer and the Company. The details of such construction and equipment are subject to negotiation between the Company and the customer before service is supplied.

302.4 As the voltage and number of phases which will be supplied depend upon the character of the load, its size, and location, it is necessary that the customer consult with the Company regarding the type of service which will be furnished before proceeding with the purchase of equipment or the installation of wiring. (Refer to Paragraph 105)

302.5 The customer's wiring for single phase installations shall be such that the difference in loads on each side of the supply neutral shall not exceed 10% of the total load.

302.6 For three phase grounded wye installations, the load shall be balanced so that the difference in loads on the separate phases shall not exceed 10% of the total load.

303. Primary Voltages (See also Section 500.)
Service may be made available at primary voltage of 2400 volts or higher. The available primary voltage is dependent upon the local primary voltage.

Section 400 - SECONDARY VOLTAGE SERVICE
(Under 600 Volts)

401. Secondary Voltage Service Connections
The location of the service connection is subject to approval by the Company. The Company will cooperate with the customer to the fullest extent practicable in determining such location. Once established, any change by the customer may result in billing to the customer for any additional work or materials required by the Company.

402. Service Connections and Disconnections
All connections or disconnections of overhead or underground services, regardless of the voltage, will be made by the Company at the point where the Company's facilities join those of the customer. No customer or agent of the customer will be authorized to make such connections or disconnections. (Refer to § III.1. and Paragraphs 103 and 104)

403. Number of Service Drops
In general, one service drop will be installed for each customer location. Exceptions will be made in special cases where it is mutually advantageous to the customer and the Company.

404. Services in Raceways
Where services are installed in raceways, the installations must comply with the requirements of the latest edition of the National Electrical Code. In addition, effective with services installed on and after April 25, 2006 metered conductors shall not be installed in the same raceway as unmetered service conductors.

405. Service Entrance Requirements
405.1 The Company recommends that the service entrance for single family residences be not less than 100 ampere. The service entrance shall be sized and installed in accordance with provisions of the National Electrical Code, state code, and local ordinances. Bare neutral wire shall not be installed in metallic conduit due to the possibility of radio interference.

405.2 Ample length of service entrance conductor shall be left protruding from the service head and at padmount equipment facilities to allow for proper connection to the service drop for overhead installations and to padmount equipment terminals.

405.3 When entrances are parallel in two or more conduits, all phases shall be run in each conduit and all wires shall be of the same length.

406. Identification of Conductors
406.1 For purposes of identification, the neutral wire of each single phase entrance shall be clearly marked at the service outlet as well as at the meter location.

406.2 Where 4-wire, three phase service entrances are installed, the neutral conductor and the "wild" phase conductor (nominal 208 volts to ground) shall each be clearly marked at the service outlet, at the meter and at service equipment.

407. Overhead Service Drops
407.1 The service entrance shall preferably be through the eave and be located so the overhead service drop will be as short as practical and maintain all clearance requirements. (Refer to Figure 1 and Paragraph 407.4)

407.2 In cases where proper clearances cannot be maintained by attaching the service drop directly to the building, the customer shall install and maintain a supporting

structure of sufficient mechanical strength to support the wires and of sufficient height to provide the necessary clearances.

407.3 The customer shall furnish and install the necessary facilities for firmly mounting a Company supplied service drop attachment.

407.4 Service drop conductors shall not be readily accessible and when not in excess of 750 volts, shall conform to the following general requirements (Refer to the National Electrical Safety Code for possible exceptions) :

Clearance over roof – Multiplex service drop conductors shall have the following minimum clearance over a roof:

10.0 feet - from the highest point of roofs or balconies over which they pass with the following exceptions:

Exception 1: The clearance shall be maintained at not less than 3.0 feet above roof or balcony not readily accessible.

Exception 2: Where a roof or a balcony is not readily accessible, and a service drop passes over a roof to terminate as a (through-the-roof) raceway or approved support located not more than 4.0 feet, measured horizontally from the edge of the roof, the clearance above the roof shall be maintained at not less than 1.5 feet for a horizontal distance of 6.0 feet from the raceway or support, and shall be maintained at not less than 3.0 feet for the remainder of the horizontal distance that the cable or conductor passes over the roof.

Note: A roof or balcony is considered readily accessible to a person, on foot, who neither exerts extraordinary physical effort nor employs special tools or devices to gain entry.

Clearance from ground – Multiplex service drop conductors shall have the following minimum clearance from ground:

18.0 feet - over roads, streets and other areas subject to truck traffic. Trucks are defined as any vehicle exceeding 8 feet in height.

18.0 feet - over driveways, parking lots and alleys. This clearance may be reduced to the following values:
(1) 17 feet – where multiplex service drops cross over or run along alleys, driveways, or parking lots.
(2) If the height of attachment to a building or other installations does not permit these requirements:
(a) 14 feet – over residential driveways for multiplex service drops limited to 150 volts to ground.
(b) 10 feet – over residential driveways for drip loops of service drops limited to 150 volts to ground.

14.0 feet - over spaces or ways accessible to pedestrians or restricted traffic only. This clearance may be reduced to the following values:
(1) If the height of attachment to a building or other installations does not permit these requirements:
(a) 12 feet - for multiplex service drops limited to 150 volts to ground.
(b) 10 feet - for drip loops of service drops limited to 150 volts to ground.

24.5 feet - over swimming pools, or within 10 feet, measured horizontally, of the pool edge. In addition, there must be 16.5 feet clearance measured in any direction from every point on a diving platform or tower.

The vertical clearance is derived using the latest edition of the National Electrical Safety Code rule and, where necessary, adding 2 feet for vertical movement safety factor adopted by Company.

408. Secondary Voltage Underground Service

408.1 Where the customer desires an underground service, the customer must furnish and install conduit from the line side of the meter socket to a point a minimum of 18

inches below grade. (Refer to Figure 1.) The customer shall also provide necessary conduit for services under any asphalt or concrete drive-way, walkway, parking lot, or other areas where it is impractical to excavate.

408.2 If a customer requests to convert from an overhead service to an underground service, the customer must provide all necessary changes to the service entrance, including relocation, and the conduit described in 408.1 above. The customer must also provide a Company approved trench ready to accept the underground service conductors including back filling, surface restoration and any future settlement or erosion. If the customer requests the Company to provide this work, the Company will charge the customer for this service. In addition, if the service length is less than 150 feet, a fee equal to the Company's labor and equipment costs to convert the average 100 feet service line will be charged. If the service length is greater than 150 feet the customer will pay a fee equivalent to the Company's actual labor and equipment costs for the conversion.

409. Mobile Home Service

The customer shall install and maintain the metering pedestal or meter socket and meter mounting device. The customer, as the term is used in this section, is considered to be the mobile home court owner for installations in mobile home courts and the mobile home owner for installations on a private lot.

Section 500 - PRIMARY VOLTAGE SERVICE
(2400 Volts or More)

501. General

The Company offers electric service at primary voltages of 2400 volts or higher. A customer desiring to take service at primary voltage shall furnish and own all electrical equipment from the point of delivery and shall consult the Company to assist in determining the size, type and arrangement of service entrance equipment and conductor specifications required for the customer's particular needs.

502. Service Entrance Equipment

The service entrance equipment shall perform the following functions:

a. Isolate the load from the supply circuit by visible means.
b. Automatically break the circuit in the event of overload.
c. Permit manual opening of the circuit at full load.

503. Overcurrent Protection
The need for overcurrent protective coordination requires consultation with the Company. Overcurrent protective devices may be as follows:

a. Fuses
b. Automatic trip circuit breakers

The overcurrent protective device must have an interrupting rating, at circuit voltage, equal to or exceeding the maximum short circuit current available at the location where service is taken.

504. Disconnecting Means
504.1 The disconnect switch shall provide visible evidence that the circuit to which it is applied is open or disconnected. It shall be located on the supply side of the circuit.

504.2 Where fuses are used, the disconnect switch shall be a gang operated load break switch.

504.3 Where automatic circuit breakers are used as circuit protective equipment, the disconnect switch can be non-load break.

505. Load Balance
Loads on the three phases shall be balanced as closely as possible. The maximum unbalance permitted between individual phase loads is 10% of the total three phase load.

Section 600 - METERING

601. General
The Company will install the necessary meters to measure the electrical energy delivered under each account for a particular class of service. The Company shall install and maintain at its own expense all equipment necessary to regulate and measure the commodity delivered per tariff.

601.1 Meter Reading and Billing

a. Each service meter shall clearly indicate the units of measurement. If the utility bills customers in a different unit of measurement than the service

meter indicates, the conversion factor shall be stated on the customer bill. In cases where special types of meters are used or where the readings of a meter must be multiplied by a constant to obtain the units consumed, that information shall be placed on the customer bill.

b. Bills shall be rendered periodically and shall show the meter readings at the beginning and end of the billing period, the date of the meter readings, the units consumed, the class of service and other information necessary to enable the customer to readily re-compute the amount of the bill. Each bill shall bear upon its face the date of the bill and the latest date it may be paid without penalty. Estimated meter readings or budget billing shall be clearly identified on the bill. Electric meters shall be read monthly as nearly as possible on the same day within the billing cycle.

602. Meter Installations

602.1 The Company will furnish all meters required for billing purposes. It shall be the customer's responsibility to furnish, install and maintain the meter mounting device. Company approved specifications for electric meter sockets and metering transformer enclosures are listed below:

Self-Contained Meter Sockets - Single Phase, Three Phase and Multiple Position Type

1. The customer will utilize meter sockets from a Company approved list of manufacturer and models as posted on the company's website.
2. U.L. approved, ringless style.
3. 100 ampere minimum for overhead service installations. 200 ampere minimum for underground service installations.
4. Stud connectors are required for all socket rated 320 amps of greater.
5. For sockets rated below 230 amps, stud connectors are recommended. Only Company specified meter sockets are approved with lay-in connectors.
6. Equipped with a fifth terminal in the nine o'clock position where network metering is required.
7. A lever by-pass feature is required for all commercial and industrial installations. Upon review by Company, an exemption may be provided.

8. A lever by-pass feature is recommended for all residential installations.

Metering Transformer Rated Meter Socket

1. U.L. approved, ringless style with a one piece cover.
2. Minimum size must provide space for test switch installation.
3. Socket must have six terminals for single phase and 13 terminals for all other configurations.
4. Automatic by-pass feature is not acceptable.
5. The customer will utilize instrument rated meter sockets from a Company approved list of manufacturer and models.

Metering Transformer Enclosure (Secondary Service)

1. Recommend a durable, weather-resistant finish and weather-proof seal.
2. Must be provided with hinge-type cover and provisions to attach locking or sealing device.
3. Minimum size 10" x 24" x 30" with suitable mounting brackets for current and voltage transformers.
4. Consult with Company prior to purchasing any metering transformer enclosure.

602.2 Self-contained rate meter sockets shall be placed outdoors.

602.3 On instrument rated meter sockets, the Company will furnish and install the metering transformers. Such meter sockets shall be arranged for outdoor metering. (Refer to Figures 2 and 3)

602.4 Where a secondary metering transformer enclosure is required, the customer shall furnish and install an enclosure. Such enclosures shall contain only the service entrance conductors and metering transformers. The metering transformers shall be installed on the line side of the customer's disconnecting device. Suitable lugs, connectors, etc. for connecting metering transformers to service mains shall be provided by the customer. (Refer to Paragraph 602.1)

602.5 For installations having switchboards, the metering transformers may be mounted in the switchboard bus, provided they are accessible for changing and testing. Metering transformers shall be mounted on the source side of the main switch.

602.6 Meters and test switches may be mounted on a suitable unhinged panel adjacent to the metering transformer enclosure.

602.7 No device other than a Company-owned or Company-approved device shall be placed into or ahead of the meter socket.

603. Meter-Switch-Fuse Wiring Sequence

For all secondary voltage metering installations, the meter entrance switch and main line fuse or breaker shall be installed in the order named with respect to power flow. All circuits downstream from the meter shall have proper overcurrent protection devices. Additionally, for 480 volt installations, a ~~A~~ customer-owned main service switch shall be installed on the source side of all 480 volt, self-contained meters. This switch shall be located no closer than three feet either left or right of the meter socket, and the switch cover is sealed by the Company. The switch shall be labeled “Utility Disconnect”. By exception and upon consultation with the Company, an overcurrent circuit breaker may be installed ahead of a gang style metering installation with 6 or more sockets as an Emergency Disconnect. Access to the Emergency Disconnect Switch shall be lockable and shall be locked by the Company.

604. Meter Locations

604.1 Each meter shall be located outdoors in a place of convenient access where it will not create a hazard. The location shall be agreed upon by the customer's representative and the Company and in compliance with Chapter 3, Section 16 of the Wyoming Public Service Commission’s Rules. (Refer to Figure 1)

604.2 Meters shall be located so that there is not less than 3 feet of unobstructed space, from the ground up, in front of the meter so that the center line of the meter is not less than 4 feet nor more than 5 feet above the floor, ground, or permanent platform from which the reading will be taken. On group installations, the minimum height is 2 feet – 6 inches and the maximum is 6 feet. The minimum center spacing between meter sockets shall be 7 ½ inches horizontally and 8 ½ inches vertically.

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

State of Wyoming
Electric Rate Schedule

CONDITIONS OF SERVICE Rate 100

604.3 Meter Sockets shall be permanently mounted on secure structures such as houses, buildings, poles, etc. All required conduit will be provided by the customer. (Refer to Figures 1, 2 and 3)

604.4 Enclosures shall not be placed over the meter socket unless approved by the Company.

605. Indoor Metering
Meters shall be located outdoors as noted in Paragraph 604.1. However, depending on the circumstance and after consulting with the Company, locating the meters indoors may be approved on a case by case basis. Where approved, indoor meters for multiple dwellings, large office buildings, etc. shall be grouped and located as near the service entrance location as practicable. In the event such location renders the automatic meter reading equipment ineffective customer will be responsible for costs associated with remedying the situation.

606. Wiring Diagrams
Typical wiring diagrams for various types of self-contained meters are shown on Figure 4. These are subject to change from time to time with advancement in available metering equipment.

607. Labeling
Where two or more meter mounting devices are installed at one location, each shall be labeled so that it may be identified as to the customer served. Electrical contractors are requested and cautioned to check and identify wiring circuits carefully to avoid metering errors due to incorrect circuitry. Permanent (mechanically fastened) engraved plates shall be placed on the exterior of the meter base on a non-removable panel.

608. Seals
All meters and all points of access to customer wiring on the source side of the meter will be sealed by the Company. All cabinets and switch boxes, either inside or outside of the building, which contain unmetered wires shall have provisions made for sealing before service will be supplied.

Section 700 - UTILIZATION EQUIPMENT

701. Interfering Loads
Whenever a customer's utilization equipment has characteristics which cause undue interference with the Company's service to other customers, the customer shall provide, at the customer's expense, the necessary equipment to prevent or eliminate such interference. The Company may install and maintain at the customer's expense and upon approval of the customer the necessary equipment to eliminate such interference if it deems it advisable. When a customer's equipment or method of operation causes

such interference and the customer does not correct the condition after being so requested by the Company, the Company reserves the right to discontinue the electric service, following written notification of its intent to do so; and service will not be re-established until the conditions complained of have been corrected.

702. Voltage Flicker and Harmonics

702.1 The Company uses the latest revision of the IEEE Standard 141 as the guideline for the maximum allowable voltage flicker that can be caused by a customer's load as measured at the point of metering. This guideline refers to the momentary dip in voltage that may result from the customer's operation of switches, starting of motors, etc.

702.2 Customer's electric load shall comply with the recommendations within Section 10 of the latest revision of the IEEE Standard 519 "Recommended Practices & Requirements for Harmonic Control in Electric Power Systems" at the point of metering connection. The IEEE Standard is available for review by the customer by contacting the Company to discuss by phone or to arrange an appointment at the Company's Sheridan office.

703. Power Factor

Whenever the customer's utilization equipment is of such characteristics as to produce a low power factor, the Company reserves the right to require the customer to raise such power factor, at the customer's expense, or to pay additional charges as provided in certain of the Company's rates on file with the Regulatory Commission of the state wherein the customer is located.

704. X-Ray Equipment

At the option of the Company, x-ray equipment may be separately metered and/or supplied from separate transformers.

705. Electric Welders

Electric welding apparatus shall require special arrangements with the Company to determine its ability to serve before installation is made. (Refer to Paragraph 703)

706. Electric Motors

706.1 Motors are normally designed to operate at their rated voltage, plus or minus 10%; thus a 220 volt motor should operate satisfactorily at 208 volts or 240 volts.

706.2 To assure adequate safety to personnel and equipment, the customer shall provide and maintain protective devices in each phase to protect all motors against overloading, short circuits, ground faults and low voltage, and to protect all three-phase motors against single-phasing and phase reversal.

706.3 Motors for use at 120 volts single-phase are limited to locked rotor currents of 25 amperes if started more than 4 times per hour, and 50 amperes if started less frequently.

Motors for use at 208 or 240 volts single-phase will generally be limited to 3 h.p. and a maximum of 4 starts per hour. The Company must be consulted for single-phase motors above 3 h.p. Compensating starting equipment may be required to limit the starting current and when required, shall be furnished by the customer. (Refer to Paragraph 702)

706.4 The size of the three-phase motors permitted will depend upon the effect starting the motor has upon the customer's system and the Company's other customers in the area. This effect will depend upon the magnitude of the starting current and the frequency of starting. (Refer to Paragraph 702)

When necessary, the customer will be required to reduce the amount of starting current to an acceptable level by installing suitable motor-starting equipment or by using motors designed for smaller starting currents.

706.5 When more than one motor can start simultaneously, the sum of the maximum starting currents of those motors starting simultaneously and also the sum of their horsepower rating shall be furnished to the Company to determine when reduced voltage starting may be required.

707. Flashing Display Signs

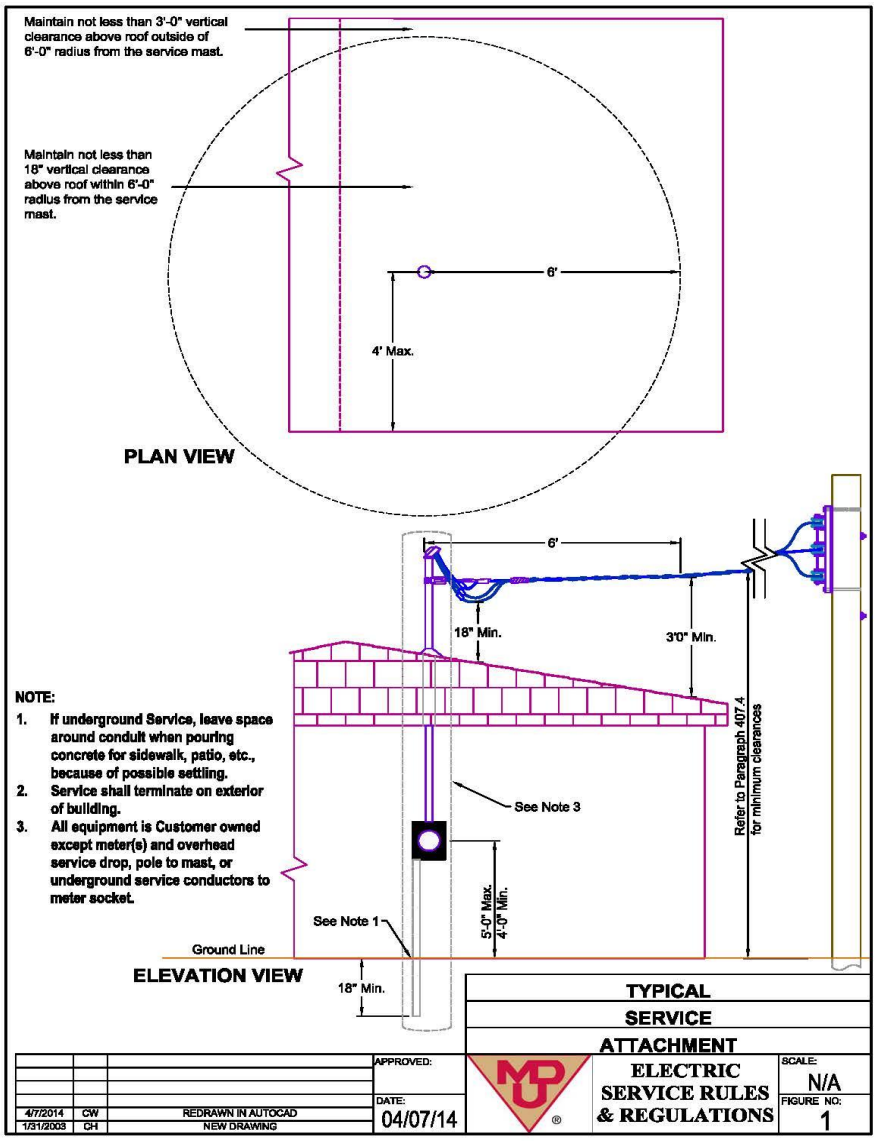
The Company reserves the right to refuse service for "flashing" display signs or display lighting where such service would interfere with voltage regulation of the secondary system.

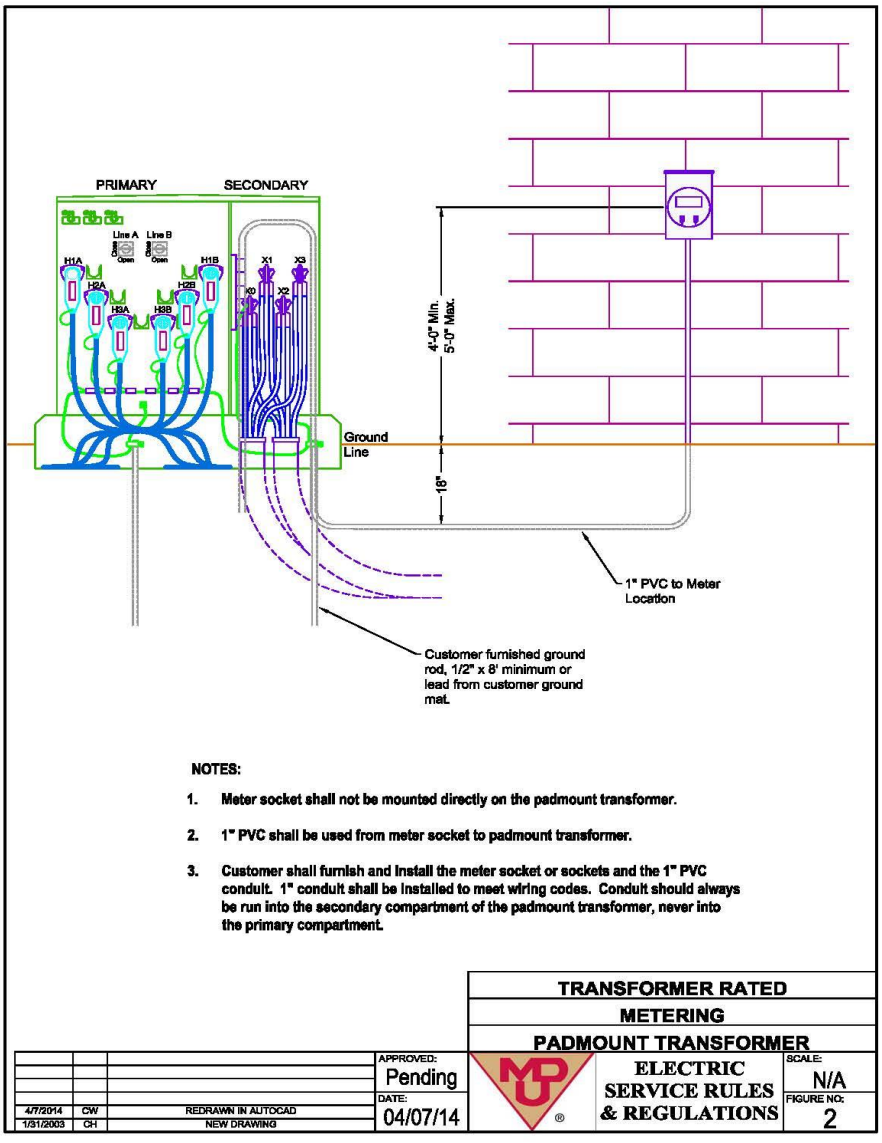
708. Fluorescent and Gaseous Tube Lighting
High power factor ballasts or transformers must be used for fluorescent, sodium vapor, neon or other gaseous tube lighting equipment. It is required that such equipment operate at a power factor of not less than 90% lagging.

709. Electric Heat Equipment
A customer planning to install resistance type heating, heat pump, electric furnace, electrode boiler, etc. shall consult with the Company, before purchasing the equipment, so that operational modes of this equipment are determined to be acceptable for connection to the Company's distribution system. It is important that consultation is obtained prior to installation of this equipment so the Company can provide adequate capacity to efficiently serve the customer's requirements.

710. Computers and Electronic Equipment
Computers and other sensitive electronic equipment which require high grade, uninterrupted power may, on occasion, experience problems when connected directly to the Company's distribution system. The customer should contact their equipment supplier or consultant to ascertain the need for lightning arresters, surge suppressors, isolation transformers, and standby or uninterruptible power supplies. (Refer to § IV.2.)

711. Carrier Equipment
The customer shall not impose, or cause to be imposed, any electric signal of any frequency or magnitude upon the Company's distribution system that may produce ill effects on Company equipment, affect safety of personnel or affect other Customers' equipment.


Maintain not less than 3'-0" vertical clearance above roof outside of 6'-0" radius from the service mast.
Maintain not less than 18" vertical clearance above roof within 6'-0" radius from the service mast.
6'
4' Max.
PLAN VIEW
6'
18" Min.
3'0" Min.
NOTE:
1. If underground Service, leave space around conduit when pouring concrete for sidewalk, patio, etc., because of possible settling.
2. Service shall terminate on exterior of building.
3. All equipment is Customer owned except meter(s) and overhead service drop, pole to mast, or underground service conductors to meter socket.
See Note 3
Refer to Paragraph 407.4 for minimum clearances
See Note 1
5'-0" Max. 4'-0" Min.
Ground Line
ELEVATION VIEW
18" Min.
TYPICAL SERVICE ATTACHMENT
APPROVED:
DATE: 04/07/14
4/7/2014 CW REDRAWN IN AUTOCAD
1/31/2003 CH NEW DRAWING
ELECTRIC SERVICE RULES & REGULATIONS
SCALE: N/A
FIGURE NO: 1

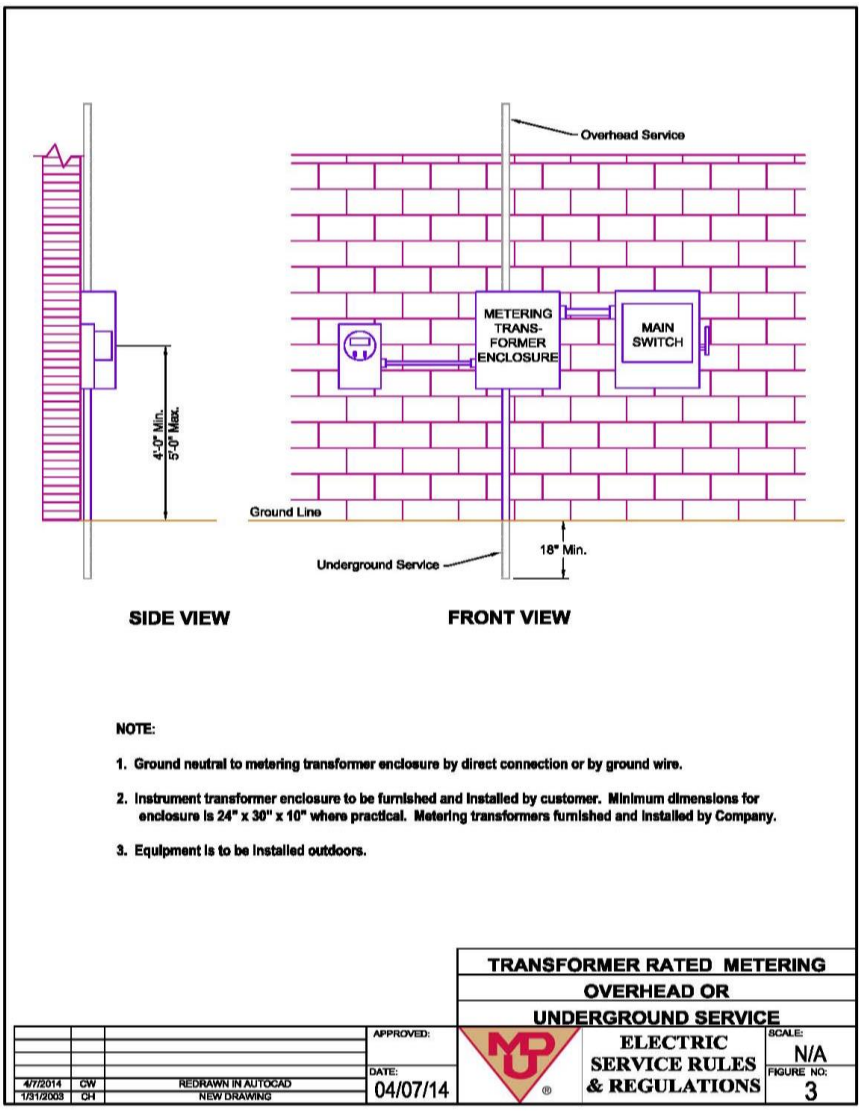


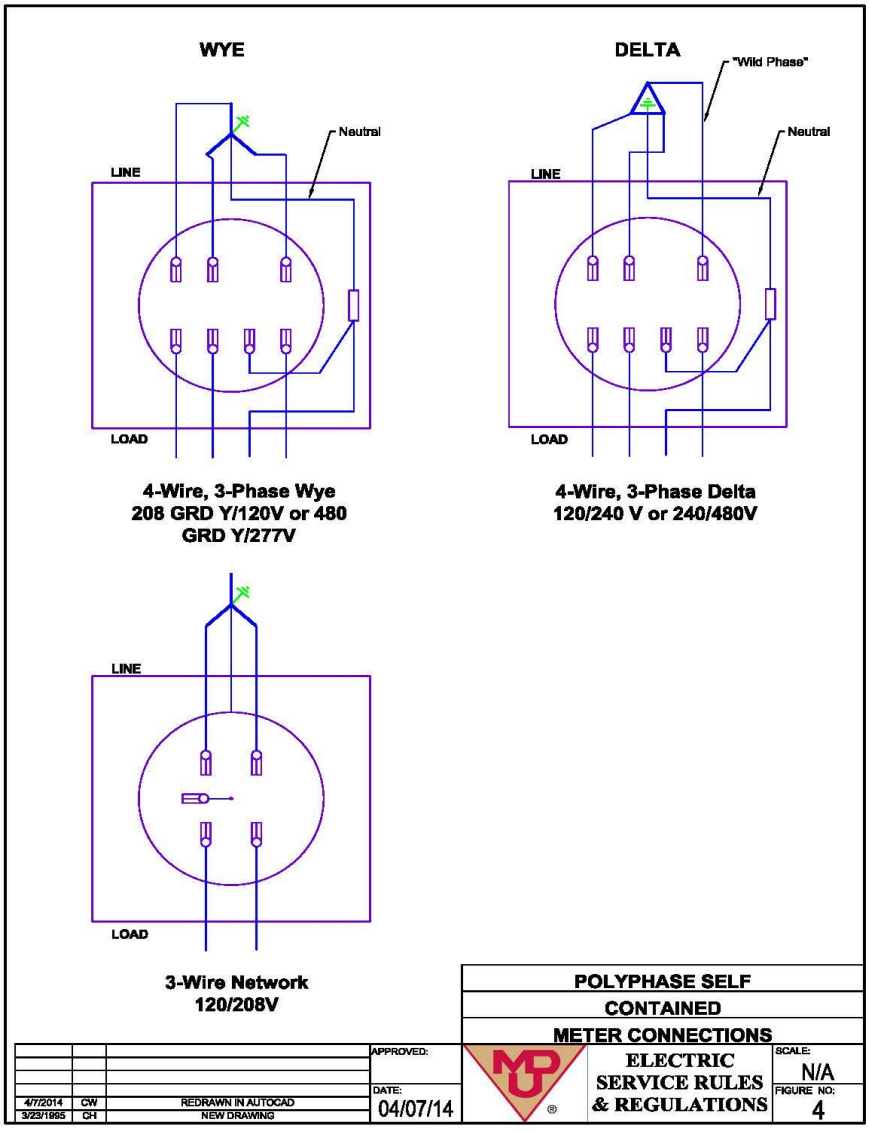
NOTES:

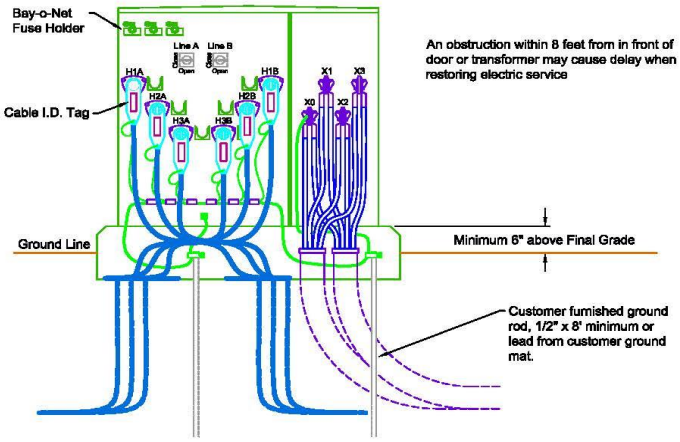
1. **Meter socket shall not be mounted directly on the padmount transformer.**
2. **1" PVC shall be used from meter socket to padmount transformer.**
3. **Customer shall furnish and install the meter socket or sockets and the 1" PVC conduit. 1" conduit shall be installed to meet wiring codes. Conduit should always be run into the secondary compartment of the padmount transformer, never into the primary compartment.**

			APPROVED: Pending	TRANSFORMER RATED METERING PADMOUNT TRANSFORMER
			DATE: 04/07/14	ELECTRIC SERVICE RULES & REGULATIONS
4/7/2014	CW	REDRAWN IN AUTOCAD		SCALE: N/A
1/31/2003	CH	NEW DRAWING		FIGURE NO: 2

CONDITIONS OF SERVICE Rate 100




WYE
Neutral
LINE
LOAD
4-Wire, 3-Phase Wye
208 GRD Y/120V or 480
GRD Y/277V
DELTA
"Wild Phase"
Neutral
LINE
LOAD
4-Wire, 3-Phase Delta
120/240 V or 240/480V
LINE
LOAD
3-Wire Network
120/208V
POLYPHASE SELF
CONTAINED
METER CONNECTIONS
APPROVED:
DATE:
04/07/14
4/7/2014 CW REDRAWN IN AUTOCAD
3/23/1995 CH NEW DRAWING
ELECTRIC
SERVICE RULES
& REGULATIONS
SCALE:
N/A
FIGURE NO:
4



NOTES:

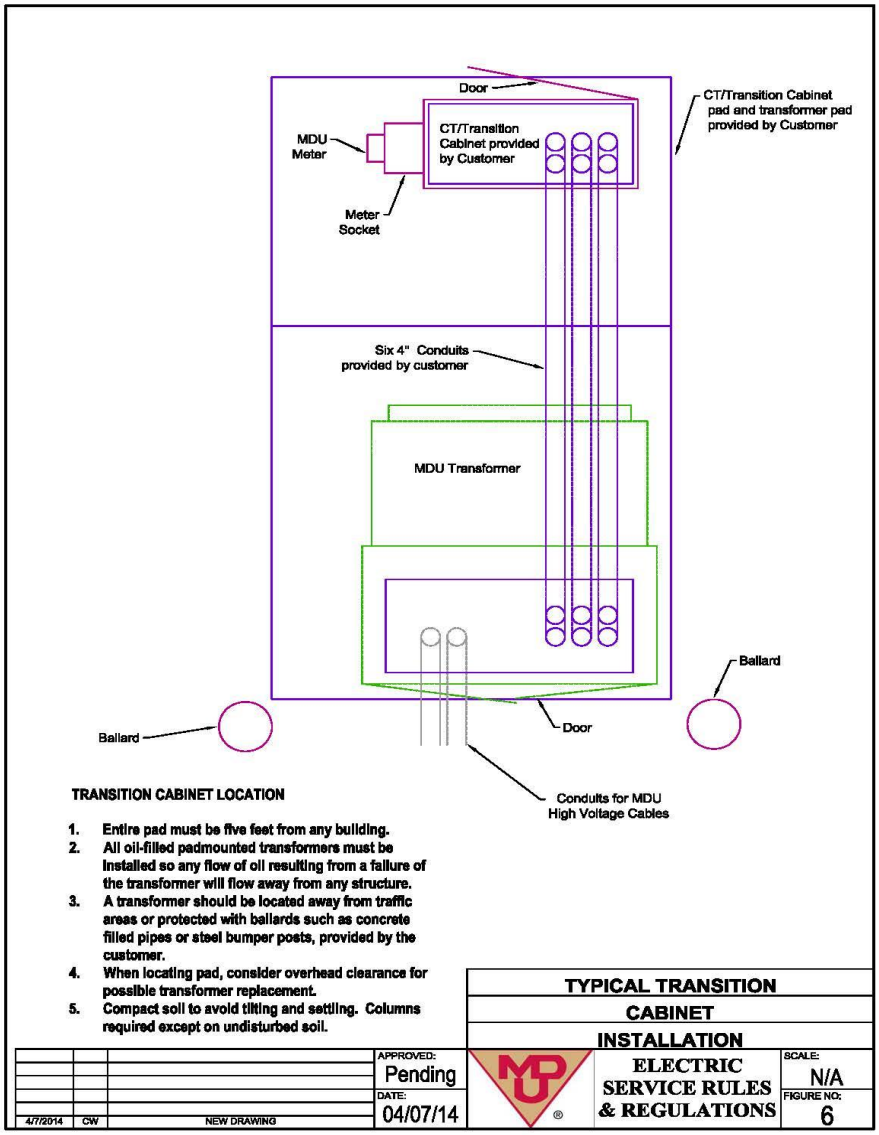
1. Consult with Company for actual equipment pad dimensions.
2. Transformer pad, service cable, conduit and ground rod or mat for service cable grounding are furnished by Customer.
3. Allow sufficient slack in service entrance conductor to allow for proper connection to equipment terminals.
4. Service connectors to be furnished by Company.
5. Connection to Company's equipment terminals to be made by Company.
6. When more than four condutors are installed for each phase, consult Company for transition cabinet requirements.

TRANSFORMER LOCATION

1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with ballards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.

TYPICAL PADMOUNT EQUIPMENT INSTALLATION

			APPROVED: Pending	ELECTRIC SERVICE RULES & REGULATIONS	SCALE: N/A
			DATE: 04/07/14		FIGURE NO: 5
4/7/2014	CW	REDRAWN IN AUTOCAD			
1/31/2003	CH	NEW DRAWING			


Door
CT/Transition Cabinet pad and transformer pad provided by Customer
MDU Meter
CT/Transition Cabinet provided by Customer
Meter Socket
Six 4" Conduits provided by customer
MDU Transformer
Ballard
Ballard
Door
Conduits for MDU High Voltage Cables
TRANSITION CABINET LOCATION
1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with ballards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.
TYPICAL TRANSITION CABINET INSTALLATION
APPROVED: Pending
DATE: 04/07/14
4/7/2014 CW NEW DRAWING
ELECTRIC SERVICE RULES & REGULATIONS
SCALE: N/A
FIGURE NO: 6

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. 160

ELECTRIC EXTENSION POLICY
Rate 104

The policy of Montana-Dakota Utilities Co. for electric extensions is to provide service to any new customer.

1. A permanent extension may be constructed without a customer or developer contribution if the estimated project cost is equal to or less than ~~2.684~~3.781 times the estimated annual revenue excluding power supply costs (~~2.684~~3.781 to 1 ratio).

2. If the estimated project cost is greater than ~~2.684~~3.781 times the estimated annual revenue excluding power supply costs, the extension will be made only with a customer contribution, which may be refundable.

   a. Contribution -

      1) When a contribution is required of any customer, with the exception of those customers defined in 2) below, the formula for determining the amount of the contribution required shall be as follows: Total project cost less ~~2.684~~3.781 times annual revenue excluding power supply costs equals contribution amount.

      2) The contribution requirement for developers of subdivisions and industrial customers shall be the estimated project cost.

      3) The contribution shall be a one-time payment prior to construction.

      4) A minimum annual bill equal to the estimated annual revenue used in the contribution formula, will be applicable for a period of five (5) years. This amount will be as set forth on the Electric Service Agreement.

      5) Upon completion of construction, where actual costs are less than the estimated construction costs, a refund will be made for the difference, but not for an amount less than $25.00. No additional contribution will be requested from the customer where actual construction costs exceed the estimate unless unusual construction difficulties are encountered.

ELECTRIC EXTENSION POLICY
Rate 104

b. Refund -

1) If within a five-year period from the date initial service is established, one or more additional customers are added to the above-referred-to extension, Company shall recompute the contribution required by combining the proposed project costs for the new customer(s) with the project costs of those customers already taking service. If, by so combining the project costs, the contribution of those customers already taking service would be less, Company shall make a proportionate refund, without interest, to those customers taking service prior to commencement of service to said additional customer(s).

2) If a customer makes a refundable contribution, the Company will refund to the customer annually, for a period of five years from the date service becomes available to the customer, an amount equal to fifty percent of the customer's bill, after first deducting the annual minimum, which minimum shall be equal to the estimated annual revenue excluding power supply costs used in the contribution formula, provided, however, that no refunds shall be made in excess of the amount contributed. The annual refund shall be paid only after the electric service bills for that year have been paid in full.

3) Refunds for developers of subdivisions shall be made for each lot connected based on the following calculation: Total refundable contribution divided by the number of lots that can be served from the extension equals refund per lot. In addition, the total revenue excluding power supply costs of the subdivision will be reviewed annually to determine if adequate revenues are being generated so that the contribution formula would indicate a zero contribution. When this revenue level is reached, a refund will be made to the developer equal to the remaining contribution amount still held by the Company.

4) No refund shall be made by Company to customer(s) or developer after the aforementioned five-year period has expired.

5) No interest will be paid by Company to customer(s) on any amount customer(s) has paid to Company as a contribution in aid of construction for the project.

3. Project cost shall exclude the service line(s), transformer(s), and meter. The service line is considered to be the low voltage conductors between the Company owned transformer or secondary system and the customer owned service entrance equipment.

4. Company will deliver electricity to customer at the same rate approved by the Wyoming Public Service Commission.

5. Where a contribution in aid of construction is required to provide service, such extension is subject to prior execution by customer and Company of Company's standard agreement for extensions.

6. Where abnormal conditions exist, causing extraordinary costs on any part of the extension (e.g., railroad or river crossing, land clearing, special permits, etc.), a charge may be made equal to the additional cost incurred by reason of the abnormal conditions.

7. Temporary loads, such as gravel pit operations, carnivals, etc., shall follow the Company rules for temporary services.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. 165

DARK SKY LIGHTING SERVICE
Rate 105

AVAILABILITY:

Optional customer owned lighting apparatus defined as any shield, cover or other device that is designed to minimize light illuminating unintended areas and maintain dark skies in accordance with Wyoming Statute Annotated §37-16-201 to 202. Such lighting fixture shall be used with or on a lamp served by Company under an otherwise applicable electric service rate schedule.

RATE:

Customer requesting such lighting apparatus shall be required to pay in full the actual cost of the materials and installation prior to installation of lighting apparatus.

GENERAL TERMS AND CONDITIONS:

1. Costs for the lighting apparatus shall be not subsidized by revenue from other Company provided services.

2. The Customer shall request in writing the lighting apparatus to be installed, the location of the installation and the illumination control desired.

3. The foregoing schedule is subject to Rates 100-125 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. 167

SERVICE INTERRUPTION REPORTING PLAN
Rate 106

The following sets forth the Company's Service Interruption Reporting Plan as required in Chapter 3, Section 27-28 of the Wyoming Public Service Commission's (Commission) Rules applicable to service provided by the Company in its Wyoming service territories.

A. Definitions of Service Interruptions:

1. Major Service Interruption shall be defined as:

   a. An event that results in estimated property damage of at least $50,000;

   b. An event that results in death, in-patient hospitalization, damage to the Company's property which substantially affects service to the public or is otherwise significant in the judgement of the Company;

   c. A sustained single feeder outage of two hours or longer to the lesser of 500 customers or 50 percent of the customers served;

   d. The loss of service to a distribution substation feeder or;

   e. Any service interruption which affects twenty five (25) or more customers for eight (8) hours or longer.

   Minor Service Interruption shall be defined as any sustained service interruption which affects at least one customer and is not defined as a Reportable Incident.

2. Scheduled Service Interruption shall be defined as:

   a. Any service interruption scheduled by the Company which is expected to last four (4) hours or longer, or

   b. Any sustained service interruption scheduled by the Company which is expected to affect twenty-five (25) or more customers.

   Sustained Reportable Incident shall be defined as any service interruption lasting more than five (5) minutes.

B. Customer Notification Requirements:

1. Reasonable effort will be made to notify affected customers at least forty-

eight (48) hours prior to a Scheduled Service Interruption. Scheduled Service Interruptions that will occur on a Monday will require customer notification on the previous Thursday.

2. In the event of an emergency causing the Company to take a Scheduled Service Interruption in less than forty-eight (48) hours, customers will be notified as soon as practical.

C. Commission Notification Requirements:

1. Scheduled Service Interruption:

a. The Commission will be notified at least forty-eight (48) hours prior to a Scheduled Service Interruption. Scheduled Service Interruptions that will occur on a Monday will require Commission notification on the previous Thursday.

b. In the event of an emergency causing the Company to take a Scheduled Service Interruption in less than forty-eight (48) hours, the Commission will be notified as soon as practical.

2. Nonscheduled Service Interruption:

a. The Commission will be notified within two (2) hours of the known commencement of a Reportable Incident using the Commission's Service Interruption Reporting Telephone number (SIRT). Within 24 hours, the Company will follow up with an email report in conformance with Chapter 3, Section 27(f) of the Commission's Rules.

b. Reports to the Commission shall include, but not be limited to:

i. Location and geographic extent;

ii. Damage assessment, explaining the risks and likely effects on the public, the utility's customers, other utilities and telecommunications services;

iii. Date and time the service interruption began;

iv. Number of customers or individuals affected;

v. Cause, if known;

SERVICE INTERRUPTION REPORTING PLAN
Rate 106

vi. Estimated time of service restoration and basis for estimate;

vii. Any deaths or injuries;

viii. Efforts being undertaken to restore service;

ix. Efforts being undertaken to assist affected individuals;

x. Other governmental agencies notified;

xi. Contact information for reporting individual(s)

xii. If the event is ongoing, the time interval until the Commission will be updated; and

xiii. Any other information that may be necessary to assess threats or damage.

D. Commission Reporting Requirements:

1. Quarterly reports of all Service Interruptions greater than five minutes other than meter testing or change outs will be filed with the Commission within 30 days after the end of each calendar quarter in conformance with Chapter 3, Section 28 of the Commission's Rules.
2. These records shall be retained by the Company for a minimum of six years.
3. The Company shall annually review its Service Interruption Reporting Plan with any proposed modifications and definitions of major or minor service interruptions specific to the utility's system, filed with the Commission by May 1. If, after the Company's review, there is no change to the Service Interruption Reporting Plan, the Company shall so notify the Commission by letter by May 1.

E. Reportable Incident Contact Information:

1. The Company shall submit a list of contact personnel (names and phone numbers) to be contacted during a Major Reportable Incident.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. ~~170~~167.3

SERVICE INTERRUPTION REPORTING PLAN
Rate 106

2. The contact list shall be reviewed by Montana-Dakota and updated when necessary. The Company will also confirm the list remains current by notifying the Commission by January 1 and July 1 of each calendar year.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. 185

ELECTRIC METER TESTING PROGRAM
Rate 115

APPLICABILITY:

This rate schedule specifies the protocol to be followed for the testing of electric meters in accordance with Chapter 3, Section 18 of the Commission Procedural Rules and Regulations (Commission Rules).

NEW METERS:

A sampling of 5% of new meters will be tested at full load and at light load. If any meter is found to be off more than ±1%, the entire lot will be tested or rejected.

RESIDENTIAL WATTHOUR METERS IN SERVICE:

1. A random selection of meters from each decade – 1980's, 1990's, etc., will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense. At the time the random selection is made, meters less than five years old and active meters that have been tested in the last five years, will be excluded from the population to be randomly sampled.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 96% of the meters shall be not more than +/- 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 96% of the meters in a given vintage class fail to meet the requirements of +/- 2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of four years. In the event the meter type failing the +/- 2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

COMMERICAL WATTHOUR METER IN SERVICE:

1. A random selection of solid state meters from each decade – 1980's, 1990's, etc. will be tested annually at full load and light load. The sample size will depend on

lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense. At the time the random selection is made, meters less than five years old and active meters that have been tested in the last five years, will be excluded from the population to be randomly sampled.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 98% of the meters shall be not more than +/- 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 98% of the meters in a given vintage class fail to meet the requirements of +/- 2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of two years. In the event the meter type failing the +/- 2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of two years rather than the entire vintage class.

INDUSTRIAL WATTHOUR METERS IN SERVICE:

1. A random selection of solid state meters from each decade – 1980's, 1990's, etc. will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense. At the time the random selection is made, meters less than five years old and active meters that have been tested in the last five years, will be excluded from the population to be randomly sampled.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 99% of the meters shall be not more than +/- 2% in error at both light load and full load, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 99% of the meters fail to meet these requirements, the entire vintage class will be tested and adjusted or, if more economic, replaced within two years. In the event the meter type failing the +/- 2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of two years rather than the entire vintage class.

METER TEST EQUIPMENT:

1. All equipment used for testing and calibration shall be cared for and maintained as recommended in the manufacturer's operating and maintenance manuals. Appropriate carrying cases designed for the purpose shall be used when such equipment is transported to and from its normal service location.

2. Meters and other equipment which will be used as a reference standard to certify other equipment shall be kept in a temperature stable environment and shall be calibrated annually except as noted herein.

3. Meters and other equipment which are used as a reference standard shall only be used for calibration purposes, and shall not be used for trouble shooting, corrective maintenance or any other activity which might jeopardize the integrity of the instrument for calibration accuracy.

4. Calibration of the items used by the utility for reference standards shall be accomplished by an instrument with a higher degree of accuracy than the item being calibrated with the accuracy of said instrument being traceable to the National Institute of Standards and Technology (NIST).

5. Current transformers are burden tested at the time the meter is tested. A field test set is connected in series with the secondary of the metering current transformer, at the test switch. The test switch is opened, and the transformer secondary is shorted out. Each current transformer is tested first at the maximum burden, and, if the current drops, the burden is decreased until no change is observed. Appendices with the test set are used to evaluate the results to determine if the current transformer is performing satisfactorily.

6. Voltage transformers are tested by applying a test voltage to determine if the appropriate ratio is obtained.

7. Whenever any electric meter is tested, the test record shall be preserved, including the information necessary for identifying the meter, the reason for making the test, the reading of the meter upon removal from service and the result of the test, together with all data taken at the time of the test in sufficiently complete form to permit the convenient checking of the methods employed and the calculations for the life of the meter.

8. The Company shall perform meter testing using the equipment identified in the table below.

Type	Manufacturer	Used for	Degree of Accuracy	Calibration Interval
RM-17	Radian	Watt-hour Meter Standard	±0.05%	12 Months
RB-20	Radian	Watt-hour Meter Standard	±0.05%	12 Months

9. The Company shall perform calibration checks on the above identified testing equipment using the equipment identified in the table below.

Type	Manufacturer	Used to Test Equipment Types	Degree of Accuracy	Calibration Interval
RD-21	Scientific Columbus	RM-17 RB-20	See Note 1/	12 Months

Note 1/:
Accuracy: Errors expressed in percent of reading for normal operating conditions. Guaranteed accuracy specification includes stability, traceability, uncertainty, power factor, and test system errors.

1. Normal Operating Conditions:
   i. Ambient Temperature: -20°C to 70°C (-4°F to 158°F)
   ii. Relative Humidity: 0% to 95%
   iii. Auxiliary Power Voltage: 60 – 600 volts (Autoranging)
   iv. Frequency: 45 to 65 Hz
   v. Orientation: Any
2. Influences Affecting Accuracy:
   i. Temperature influence outside normal operating temperature range per °C: ±0.0005%
   ii. For Power Factors of 100% and 50% output for Whrs, VARhrs, VAhrs: no impact on accuracy
   iii. For power factor of <0.5 (PF between - 60° and -90°, then guaranteed accuracy is ±0.02%/PF.

10. These instruments are in turn calibrated with higher degree accuracy instruments annually. The highest degree accuracy instruments will be delivered to a manufacturer's facility once each year for calibration with their instruments that are directly traceable to the National Institute of Standards and Technology (NIST).

11. The referenced Military Standards are available for review by the customer by contacting the Company to discuss by phone or to arrange an appointment at the Company's Sheridan office.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
1st ~~Revised~~ Original Sheet No. 190
~~Canceling Original Sheet No. 190~~

AUTOPAY PLAN
Rate 122

AVAILABILITY:

The AutoPay Plan provides customers the option to automatically have their electric service bill, including miscellaneous charges, deducted from their checking account. This option is available in all communities served by the Company to all customers who voluntarily agree to participate in the AutoPay Plan and who have not issued two or more NSF checks to the Company in the preceding 12 month period and are not currently utilizing the Low Income Energy Assistance Program (LIEAP).

GENERAL TERMS AND CONDITIONS:

1. All provisions set forth in customer's otherwise applicable standard rate schedule shall apply.

2. The Company will issue a bill each month to the customer.

3. The bill will indicate that the amount shown in the "Amount Due" column will be automatically deducted from the customer's checking account each month on the due date indicated on the customer's bill.

4. All customers who accept the AutoPay Plan shall sign an authorization form.

5. The Company has the right to remove a customer from the AutoPay Plan if the financial institution has advised the Company of two NSF check instances within the preceding 12 month period. Thereafter, customer shall be again eligible to participate in the AutoPay Plan in the future providing that the customer has complied with the "Availability" section above.

6. Customers utilizing the AutoPay Plan who subsequently use the LIEAP will be removed from the AutoPay Plan by the Company.

7. The customer may cancel the use of the AutoPay Plan option by notifying the Company in writing.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 191

SUMMARY BILLING PLAN
Rate 123

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 191.1

SUMMARY BILLING PLAN
Rate 123

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2~~1~~
Original Sheet No. 200

BALANCED BILLING PLAN
Rate 125

1. SCOPE

A. The Plan provides electric customers with a method of paying for electric usage to avoid the highs and lows associated with normal monthly billing. The customer's monthly bill is computed by taking an average of the usage during the previous twelve months. Current energy rates are then applied to this average monthly usage to calculate the current payment due. Qualified customers with less than 12 month's history at their current premise are also allowed to enroll in the Plan.

B. Monthly bills rendered under this Plan, as indicated in A. above, will be based upon a moving average consumption and will normally change each month. The moving average will change slightly each month and thus appropriate dollar adjustments will be made to the billed amount each month.

C. The provisions of this Plan are applicable to all residential customers in Wyoming. Certain nonresidential electric customers served in Wyoming may qualify. Accordingly, the following nonresidential customers do not qualify for this Plan:

1. Industrial, municipal or interdepartmental electric customers.

2. Electric customers with demand meters.

3. Combination customers who have electric demand meters neither the gas and/or electric usage qualifies for the Plan.

4. Interruptible or otherwise controlled customers.

5. Seasonal, short-term or temporary customers.

6. Customers whose accounts are delinquent and who have not signed a Deferred Payment Agreement.

7. Customers whose usage patterns are not sufficiently predictable so as to permit estimation on an annual basis with a reasonable degree of certainty.

2. PROCEDURE

A. Customers must contact Company to request enrollment in the Balanced Billing Plan.

B. If the customer's account is current and otherwise qualifies for enrollment in the Plan as provided in Section I.C., the customer will be so informed at the time of customer's request and the customer's account record in the Customer Information System will be so coded.

C. As indicated in Section 1.C.6., customers who are delinquent cannot qualify for the Plan unless they are able to pay any amounts past due or enter into a Deferred Payment Agreement with the Company. The customer agrees to pay a reasonable fixed amount each month in addition to the Balanced Billing Plan payment amount until such arrears are paid in full.

D. Customers enrolled in the Plan will continue to be billed under the Plan provisions until they request removal or they are sixty days in arrears and are removed from the Plan by the Company.

E. If a customer desires to be removed from the Plan, customer must contact Company to request withdrawal from the Plan. Removal from plan will be effective following contact regarding withdrawal. Upon such removal the total unpaid balance becomes due at the next billing cycle. If a credit balance exists it may be refunded or applied to the next cycle billing, at the customer's discretion.

F. If a customer is removed from the Plan due to delinquency as indicated above, the total unpaid balance in their account becomes due and payable.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Wyoming

Docket No. 20004-___-ER-25

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 which are all subsidiaries of MDU Resources. 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 approximately 1.2 million customers across 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 Montana, the Public Utilities Commissions of Idaho, Minnesota, and South Dakota, the Public Utility Commission of Oregon and the Washington Utilities and Transportation Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Montana-Dakota's electric operations in the state of Wyoming. I will also provide an overview of the Company's request for an electric rate increase, discuss

the policies and reasons underlying the major aspects of the request and introduce the Company's Reliability and Safety Infrastructure Rider (RSIR). Finally, I will 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 electric operations in Wyoming.

A. Montana-Dakota's Wyoming electric system, commonly referred to as the Sheridan System, serves approximately 17,600 customers in six communities with the district operations office located in Sheridan, Wyoming. Montana-Dakota's Wyoming electric service area is part of the Company's Rocky Mountain operating region with the regional office located in Billings, Montana. As of December 31, 2024, the Company had 38 full and part-time employees who live and work throughout the Company's Wyoming electric and gas service area.

Montana-Dakota's customers have toll-free access to the Customer Experience Team, which includes the Credit Center, to place routine utility service requests and inquiries from 7:30 a.m. to 6:30 p.m. 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. Would you describe the power supply for Wyoming customers?

Yes, Montana-Dakota obtains its power supply, both energy and capacity, through three sources: a 25 percent ownership of WYGEN III, a coal fired electric generation facility; a Purchase Power Agreement (PPA) with Black Hills Power, Inc.; and a PPA with the City of Sheridan from Beckton Hall Hydroelectric. Montana-Dakota's ownership share in the WYGEN III supplies the first block of energy and capacity needs and the PPA's supply all remaining resources. The PPA for Black Hills Power is effective through 2028 and Beckton Hall Hydroelectric expires in 2037.

For calendar year 2024, approximately 54 percent of the energy and 51 percent of the capacity requirements were provided by WYGEN III with the remaining 46 percent of the energy and 49 percent of the capacity requirements provided through the PPAs to serve Wyoming customers. WYGEN III continues to be a cost effective and reliable part of Montana-Dakota's power supply mix for its Wyoming customers.

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 an electric rate increase?

A. Montana-Dakota is requesting an increase in its electric rates

because our current rates do not reflect the cost of providing electric service to Montana-Dakota's Wyoming customers. For the twelve months ending December 31, 2024, the Company's Rate of Return was 4.160 percent. This is below the last authorized Rate of Return of 7.245 percent in Docket No. 20004-117-ER-16.

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

A. The Company's last rate case was Docket No. 20004-117-ER-16, which resulted in an increase of $2,712,245 or an 11.05 percent overall increase. Final rates in the case became effective on and after March 1, 2017.

However, on May 1, 2019, rates were then decreased by approximately $1,140,791 in Docket No. 20004-135-ER-18 to reflect the Tax Cuts and Jobs Act of 2017 (TCJA).

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting $7,507,017 which represents a 24.36 percent increase based on a 2024 test year adjusted for known and measurable changes through 2025. This increase represents an average increase of 2.7 percent per year.

Q. Can you briefly explain the additional revenue requirement?

A. As shown in the table below, the $7.5 million increase in revenue is driven primarily by:

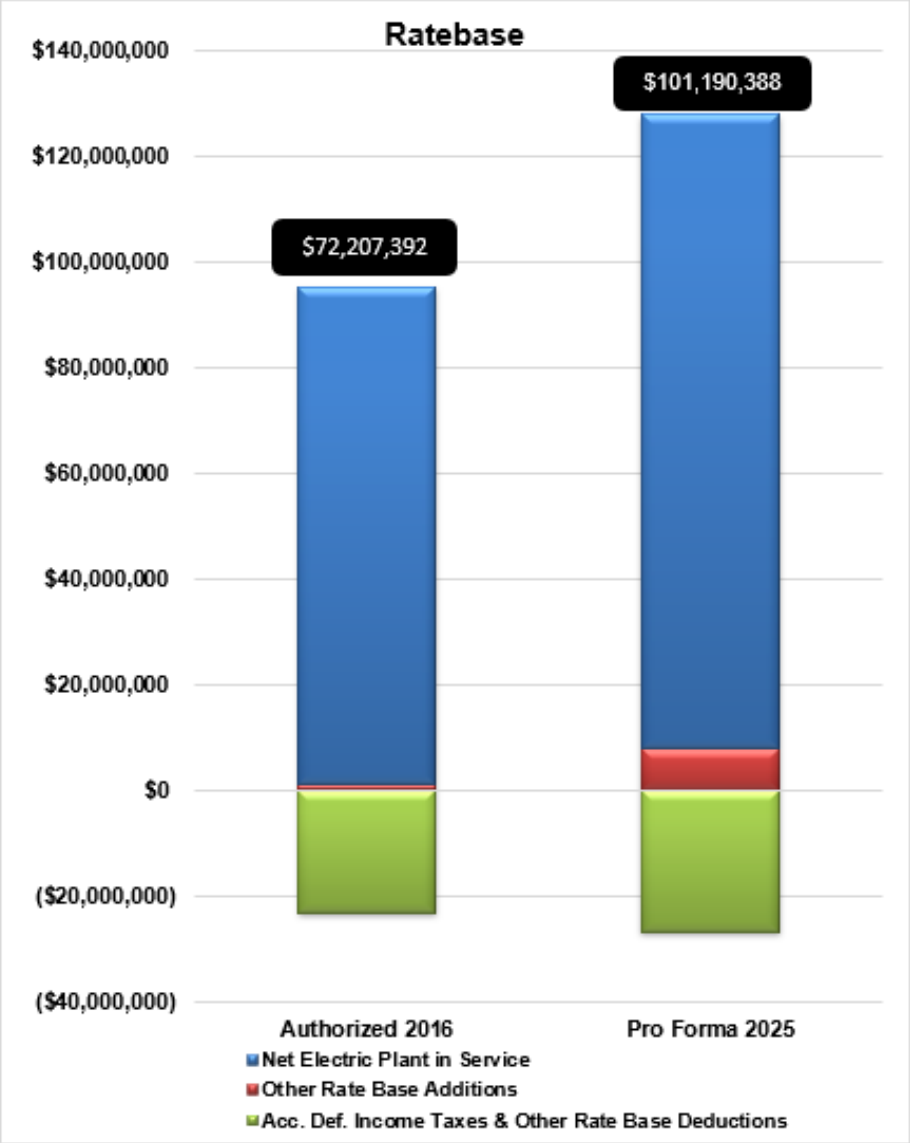
	Amount (in millions)
O&M Increase	$3.1
Rate Base	2.4
Depreciation	2.2
Change in ROE	0.9
Pension & Post Retirement	0.4
Other	0.3
Margin	(1.8)
Net Increase	$7.5

Montana-Dakota's cost of doing business in Wyoming is increasing despite the Company's effort to control costs and increase efficiency. The Company is experiencing a $3.1 million increase in O&M expenses due to increased WYGEN III costs, labor, insurance costs, subcontract labor, and software maintenance. Rate base investment since the last case includes significant distribution substation investments in 2023 and 2024 totaling approximately $6.5 million. The Big Horn to Sheridan Line covered in the testimony of Mr. Robert Frank and the WYGEN III major outage covered in the testimony of Mr. Joseph E. Geiger, represents $2.4 million of the increase. Increases in depreciation expense, primarily driven by the additional plant investment, and somewhat offset by the implementation of updated depreciation studies supported in the testimony of Mr. Larry E. Kennedy, results in a revenue requirement increase of approximately $2.2 million. Finally, the proposed addition of the provision for pension and post-retirement benefits and the proposed change in return on equity increases the revenue requirement by $0.4 million and $0.9 million, respectively. These increases are partially offset by an increase in margin,

primarily driven by customer growth, that has reduced the revenue requirement by $1.8 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 rate base has grown approximately $29 million or 40 percent when compared to the Authorized 2016 rate base.



As shown in the table below, the Company's total O&M costs have increased over those in the Company's last electric rate case. After adjusting the 2016 Authorized O&M to exclude Fuel & Purchased Power, the Company's Pro Forma O&M expenses are expected to increase approximately 45 percent. This represents a 4.20 percent compounded increase per year since the last filing.

	Authorized 2016	Pro Forma 2025	Variance	Percent Variance
Fuel & Purchased Power	$9,458,529	$12,816,969	$3,358,440	35.51%
Wygen III	2,569,549	3,560,387	990,838	38.56%
Labor	2,024,551	2,934,187	909,636	44.93%
Benefits	520,668	576,531	55,863	10.73%
Insurance	182,092	367,381	185,289	101.76%
Subcontract Labor	391,598	623,730	232,132	59.28%
Software Maintenance	82,174	312,892	230,718	280.77%
Rent	528,273	699,582	171,309	32.43%
Regulatory Commission	44,921	112,929	68,008	151.39%
Other O&M	624,974	908,125	283,151	45.31%
Total O&M Expense	$16,427,329	$22,912,713	$6,485,384	39.48%
Total Excluding Fuel & Purchased Power	$6,968,800	$10,095,744	$3,126,944	44.87%

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 2025 have increased approximately 45 percent since the 2016 rate case which represents a 4.21 percent compounded year over year increase.

Additionally, Montana-Dakota, like many other organizations in the country, is experiencing recruiting pressure due to low unemployment rates throughout our service territory. These additional pressures, when

combined with an increasing percentage of the workforce reaching traditional retirement age, 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 4.55 percent labor expense increase in 2025. This increase was necessary to ensure the Company is able to successfully compete in the labor market and retain skilled employees capable of maintaining safe and reliable service for customers. The effect of the contract 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 WYGEN III costs, insurance, subcontract labor, and software maintenance.

The operation and maintenance expenses associated with WYGEN III have increased approximately $991,000 or 39 percent since the 2016 rate case which represents a 3.69 percent compounded year over year increase. Software maintenance expense increased approximately $231,000 from the 2016 rate case which represents a 281 percent increase since the 2016 rate case. This increase is driven by increases in license renewals and mandated needs, including those related to cyber

security. Additionally, since 2016, Montana-Dakota has shifted to cloud based software licensing which has moved the expenses associated from capital to O&M.

Insurance expense has increased approximately $185,000 or 102 percent increase since the 2016 rate case which represents an 8.11 percent compound year over year increase. Finally, Subcontract Labor has increased approximately $232,000 or 59 percent since the 2016 rate case which represents a 5.31 percent compounded year over year increase. Each of the increases will be further detailed in the testimony of Ms. Vesey.

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

A. Yes. Depreciation studies for Montana-Dakota's electric and common plant in service were performed by Mr. Kennedy of Concentric Advisors, ULC. Mr. Kennedy has provided testimony on behalf of the Company. The electric study is based on plant in service as of December 31, 2020 and the common study is based on plant in service as of December 31, 2021. The impact of the depreciation study results in a Wyoming electric jurisdiction decrease of approximately $384,000 in the revenue requirement, as compared to the previously approved rates. However, despite the lower overall depreciation rates from the currently approved rates, the Company's overall depreciation expense is $2,192,000 higher than the previously approved rates due to the

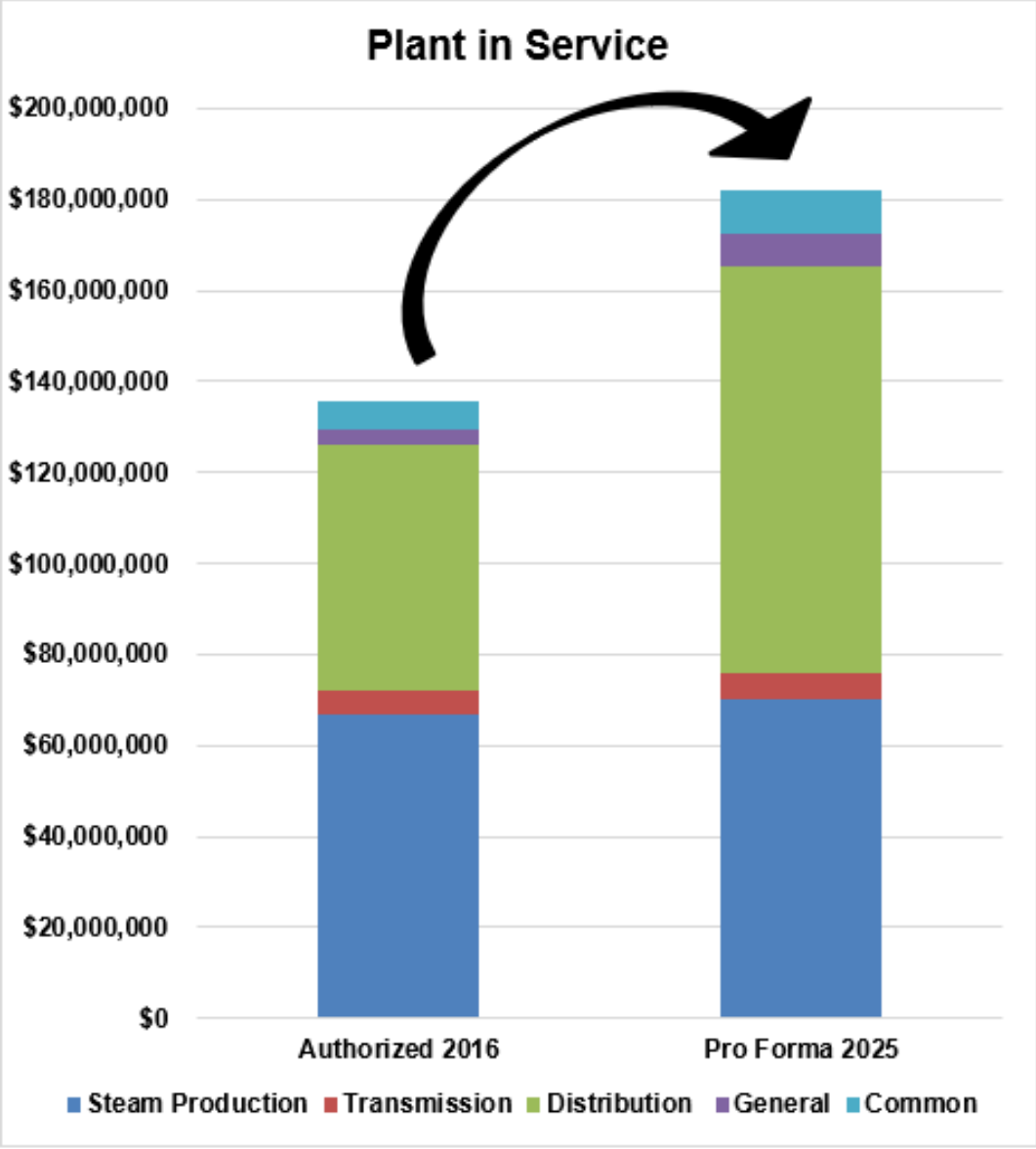
approximately 40 percent increase in gross plant investment since the last case.

Q. What incremental investments are included in this case as pro forma December 2025?

A. The Company has included incremental investments for 2025 of approximately $13.5 million as follows:

- Steam Production plant additions of approximately $2.8 million, including the WYGEN III Generator and Turbine Maintenance as discussed in greater detail by Mr. Joseph Geiger;
- Transmission plant additions of approximately $215,000;
- Distribution plant additions of approximately $9.1 million including the Big Horn to Sheridan Line project as discussed in greater detail by Mr. Frank as well as the replacement of vintage underground cables and the refinement and implementation of the Wildfire Risk Distribution Mitigation Program as discussed by Mr. Daryl Anderson;
- General plant additions of approximately $492,000 primarily associated with work equipment purchases and the Mobile Radio System implementation; and
- Common plant additions of approximately $928,000, primarily associated with the purchase of property and buildings for the Weld Shop and the implementation of the Mobile Radio System.

The table below shows the investment in plant assigned and allocated to Wyoming electric operations from Authorized 2016 to Pro Forma 2025. These investments include significant improvements in Overhead and Underground Conductors and Devices, Station Equipment, and Line Transformers.



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	26.00%
Small General Service	30.74%
Large General Service	15.15%
Irrigation Service	40.10%
Lighting	15.81%
Total	24.36%

Q. How would this increase affect an individual residential customer?

A. While the overall residential class impact shown above is 26.00%, the actual impact to customers' bills due to the rate increase will vary dependent on each customer's use and services. The Company therefore prepared an illustrative example of a residential (Rate 10) customer using approximately 800 kWh per month which results in an increase of approximately $28.00 per month. Under this illustrative example, the customer would see an increase of 29.6 percent, or an increase of approximately 3.3 percent per year.

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

A. Montana-Dakota is requesting an overall return of 7.985 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. Please describe the Reliability and Safety Infrastructure Rider Rate 55 (RSIR)?

A. The Company is proposing a RSIR which is intended to recover new or modified transmission level projects specific to the improvement of power delivery reliability to customers, replacement of pre-1985 underground distribution cables, and upgrades necessary for wildfire mitigation. The Company has identified three specific projects that the Company plans to include in future RSIR files. The project types are:

1. An Underground Vintage Cable Replacement Program discussed in detail in the testimony of Mr. Daryl Anderson;
2. A Wildfire Risk Electric Distribution Mitigation Program, also discussed in detail in the testimony of Mr. Anderson; and
3. The 41.6 kV Transmission Line Construction from Sheridan to Dayton discussed in detail in the testimony of Mr. Frank.

These projects provide safety and reliability benefits for customers but are not supported by incremental customer load. Investment in both Underground Vintage Cable Replacement and Wildfire Risk Electric Distribution Mitigation are expected to have continued investment for

several years and transmission level projects, while less routine, are generally significant investments when they do occur. Because there is no incremental load tied to these projects, Montana-Dakota's opportunity to earn its return will be diminished and the capital investment associated with these projects will accelerate the need for future general rate cases. Allowing the use of a rider mechanism will more gradually increase rates and step customers through cost increases in a more manageable transition. Additionally, the use of a rider will decrease the expense associated with filing more frequent rate cases.

Q. What is the estimated cost of the RSIR under the adjustment mechanism?

A. As discussed in the testimony of Mr. Bradley J. Davison and shown in Exhibit No.___(BJD-1), Montana-Dakota intends to invest approximately $13.9 million in 2026 and 2027 to enhance the reliability and safety of its electrical distribution system. These investments are further discussed in the testimony of Mr. Anderson and Mr. Frank and are not included in the current revenue requirement. These projects result in an annual revenue requirement of approximately $670,000. This revenue would be requested in the initial RSIR filling. This represents a monthly charge to residential customers of approximately $2.27 in order to enhance reliability and safety.

The proposed RSIR provides a mechanism that allows the Company to proactively address wildfire mitigation, replace aging

underground wires that are prone to failure, and improve power delivery reliability to customers while potentially avoiding costly rate cases and providing customers with more gradual rate increases over time. As discussed above, the projects associated with the RSIR are covered in more detail in the testimony of Mr. Anderson and Mr. Frank. The testimony of Mr. Davison will discuss the creation of the revenue requirement. The testimony of Ms. Stephanie Bosch will discuss the proposed tariff.

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 MDU Resources, 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 Wyoming electric operations.
- Mr. Daryl Anderson, Director of Electric Distribution Services for Montana-Dakota, will testify regarding two of the Company's proposed RSIR projects.

- Mr. Robert Frank, Director of Transmission Engineering, will testify regarding the Company's transmission and substation capital projects and the Company's proposed RSIR.
- Mr. Joseph E. Geiger, Director of Generation in the Power Production Department for Montana-Dakota will testify regarding WYGEN III project work.
- Mr. Larry E. Kennedy, Senior Vice President for Concentric Advisors, ULC., will testify regarding the depreciation studies for Montana-Dakota's electric and common operations of the plant in service as of December 31, 2020 and December 31, 2021 that support the proposed depreciation rates in this filing.
- Ms. Tara R. Vesey, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the total revenue requirement and pro forma volumes in this case.
- Mr. Bradley J. Davison, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the Company's proposed RSIR.
- 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 electric service to its customers. The proposed rates will provide Montana-Dakota an opportunity to earn a fair and reasonable return on its Wyoming electric operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Wyoming

Docket No. 20004-___-ER-25

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 1200 West Century Avenue, Bismarck, North Dakota 58506.

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

A. I am the Controller for MDU Resources Group, Inc. ("MDU Resources"), which includes Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company"), a wholly owned subsidiary of MDU Resources.

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

A. I am responsible for providing leadership and management of the accounting and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions.

Q. 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 23 years of experience in the utility industry. During my tenure with the Company, I have held positions of increasing responsibility, including

Financial Analyst for Montana-Dakota, Director of Accounting and Finance, and Controller.

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

A. I am responsible for presenting Statement E.

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. Please explain Statement E.

A. Statement E shows the utility capital structure of Montana-Dakota for the twelve months ended December 31, 2024, and the pro forma capital structure for 2025. Statement E includes the associated costs of debt and common equity. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 7.985 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.

The components of the 2025 pro forma annual rate of return, which are used by Ms. Tara R. Vesey to calculate the revenue requirement, are:

	Ratio	Cost	Weighted Cost of Capital
Long Term Debt	45.274%	5.060%	2.291%
Short Term Debt	3.641%	4.858%	0.177%
Common Equity	51.085%	10.800%	5.517%
Rate of Return	100.000%		7.985%

Q. How does the Company finance its electric 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, including the Big Horn to Sheridan distribution line, replacing vintage underground lines, as well as transmission upgrades to enhance reliability. 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.

In July 2024, the Company had $60 million of senior notes mature and issued long-term debt of $125 million, partially to replace the $60 million senior notes. The Company is expecting to issue $150 million of long-term debt in 2025, partially to replace $87 million of senior notes maturing. The Company received $70 million of common equity in 2024.

Additionally, on February 13, 2025, the Company entered into a definitive purchase and sale agreement with Badger Wind, LLC, to purchase a 49 percent undivided ownership interest in a wind project being constructed in North Dakota for a purchase price of $294 million. The purchase agreement is contingent on regulatory approval from the North Dakota Public Service Commission. If this purchase is approved, additional financing would be required.

Q. What does Statement E, Schedule E-1 show?

A. Page 1 is a summary showing the Company's long-term debt on December 31, 2024 and associated cost of debt, and it shows the pro forma long-term debt and associated costs for 2025. Page 2 shows the cost and the debt balance by issue on December 31, 2024. Page 3 shows the pro forma cost and the debt balance by issue on December 31, 2025, including the additional $150 million of long-term debt previously discussed.

Q. Please describe Statement E, Schedule E-2.

A. Schedule E-2 presents the twelve-month average short-term debt balance for 2024 and pro forma 2025 as well as the average cost of short-term debt. A twelve-month average of short-term debt is used in the cost of capital calculation to reflect the seasonality in the short-term debt balance. Short-term debt is historically at or near its peak in December and the twelve-month average calculation is more reflective of the borrowing level than a year-end balance.

Q. What does Statement E, Schedule E-3 show?

A. The schedule presents the common equity balance on December 31, 2024 and the projected balance for December 31, 2025 reflecting the projected activity in the balance.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
BEFORE THE WYOMING PUBLIC SERVICE COMMISSION
DOCKET NO. 20004-___-ER-25
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 Wyoming Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co, which is a wholly-owned subsidiary of MDU Resources Group, Inc. ("MDU"). My testimony addresses the regulated electric utility operations of Montana-Dakota Utilities Co. within Wyoming ("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 30 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 Montana-Dakota's return on equity ("ROE") for its electric 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 13, 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 estimate 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 considers 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 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[1] 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

[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*").

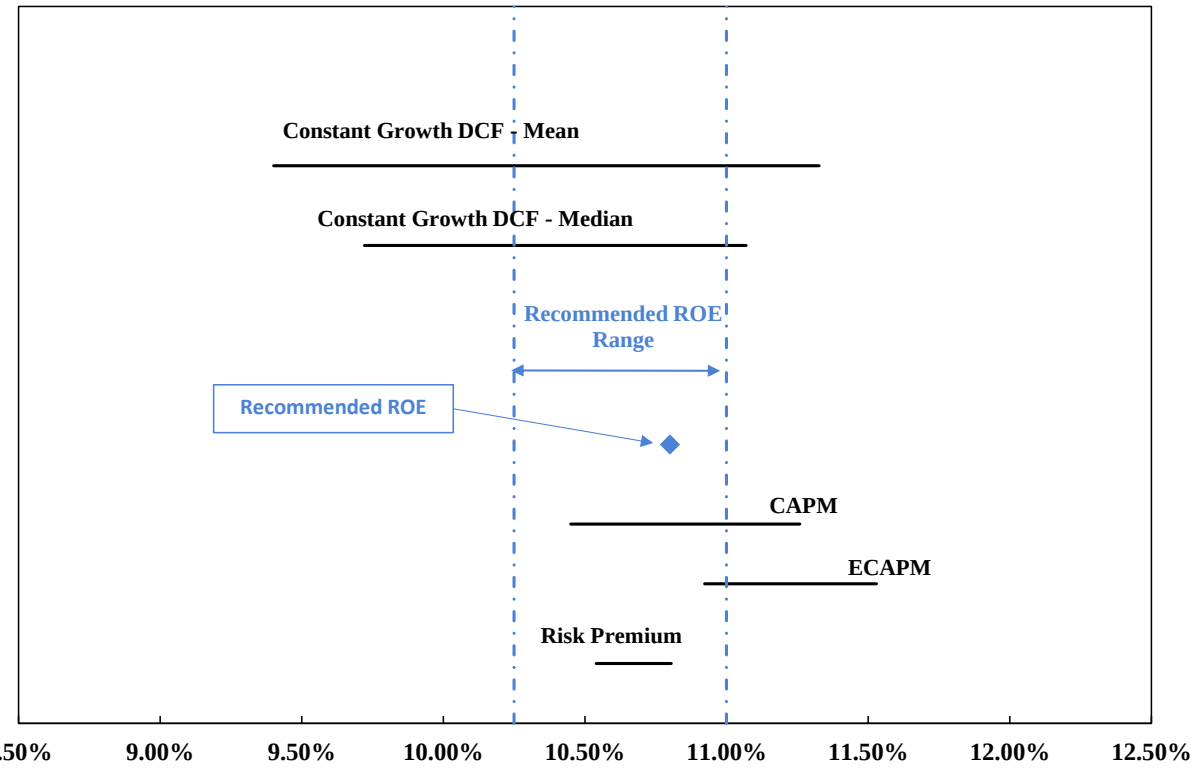
and support credit quality, and the requirement that the result lead to just and reasonable rates.

- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.
- 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



Q9. What is your recommended ROE for the Company in this proceeding?

A9. 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 11.00 percent is reasonable, and within that range, I recommended an ROE of 10.80 percent.

Q10. Is the Company's requested capital structure reasonable?

A10. Yes. The Company's proposed equity ratio of 51.085 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.

III. REGULATORY GUIDELINES

Q11. Please describe the principles that guide the establishment of the cost of capital for a regulated utility.

A11. 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]

Q12. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A12. Yes. In Docket No. 20000-ER-03-198, PacifiCorp's 2003 rate case, the Commission stated that:

> Consistent with the discretion given to the Commission in examining cases and reaching a just result (discussed generally, *infra*), there are no precise bases in Wyoming law to guide the Commission in determining a utility's rate of return on equity. Therefore, the Commission must apply its informed judgment to all of the evidence in the case. In this traditional rate-base rate-of-return case, the Commission must determine the cost of capital, and we are guided by the earnings and capital attraction standards of *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U. S. 679 (1923); and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U. S. 391 (1944); accepted in Wyoming in *In re Northern Utilities*, 70 Wyo. 275, 249 P.2d 769 (Wyo. 1952). A public utility remains entitled to rates which will permit it a reasonable opportunity to earn a return on its investment properly reflecting the risk of the business and which will reasonably preserve the financial soundness of the company and allow it to raise the capital needed to provide service in the public interest. Having said that, we also acknowledge that the measurement of the

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

> required level of return is not a matter of simple mathematics but is a matter requiring judgment and the employment of discretion. The United States Supreme Court, in *Hope*, *supra*, noted that a "just and reasonable end result" is the desired outcome and that it is the end reached, rather than the method employed in achieving it, that should control.[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.

Q13. Is fixing a fair rate of return just about protecting the utility's interests?

A13. No. As the court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[4] As the Court went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[5]

Q14. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A14. 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

---

[3] In the Application of PacifiCorp for a Retail Electric Utility Rate Increase of $41.8 Million Per Year, Docket No. 20000-ER-03-198 (Record No. 8310), Order at 11 (Feb. 28, 2004).

[4] *Bluefield*, 262 U.S. at 679, 693.

[5] *Hope*, 320 U.S. at 591, 603.

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, 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.

Q15. What is the standard for setting the ROE in any jurisdiction?

A15. 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 electric operations in Wyoming.

Q16. Does the fact that the Company is a subsidiary of MDU, a publicly-traded company, affect your analysis?

A16. 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.

Q17. Are the regulatory framework, the authorized ROE, and equity ratio important to the financial community?

A17. 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 reinforcing a utility's creditworthiness and financial stability in the jurisdiction. To the extent 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.

Q18. What are your conclusions regarding regulatory guidelines?

A18. 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: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its

financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. 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

Q19. Why is it important to analyze capital market conditions?

A19. Capital market conditions influence cost of equity models by affecting inputs in the model at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the models to estimate the required return for the subject company.

Analysts and regulatory commissions recognize the importance of considering how these conditions impact cost of equity estimation models when determining the appropriate range and recommended ROE 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 of the forward-looking period.

Q20. Do changes in capital market conditions since the Company's last rate proceeding indicate an increase in the cost of equity?

A20. Yes. As shown in Figure 2, both short-term and long-term interest rates have increased substantially since the Commission adopted the settlement agreement in the Company's last rate proceeding, which included an authorized ROE of 9.45 percent. Further, while inflation has receded from the levels seen in 2022, it remains elevated when compared to the level at the time of the Commission's decision.

Figure 2: Change in Market Conditions Since Company's Last Rate Case[6]

Docket	Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Core Inflation Rate	Auth'd ROE
20004-117-ER-16	1/18/2017	0.66%	3.07%	2.25%	9.45%
Current	5/30/2025	4.33%	4.86%	2.78%	
Change		**3.67%**	**1.79%**	**0.53%**	

Q21. What has the level of inflation been over the past few years?

A21. As shown in Figure 3, core inflation increased steadily beginning in early 2021, rising from 1.40 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982.[7] Since that time, while core inflation has declined

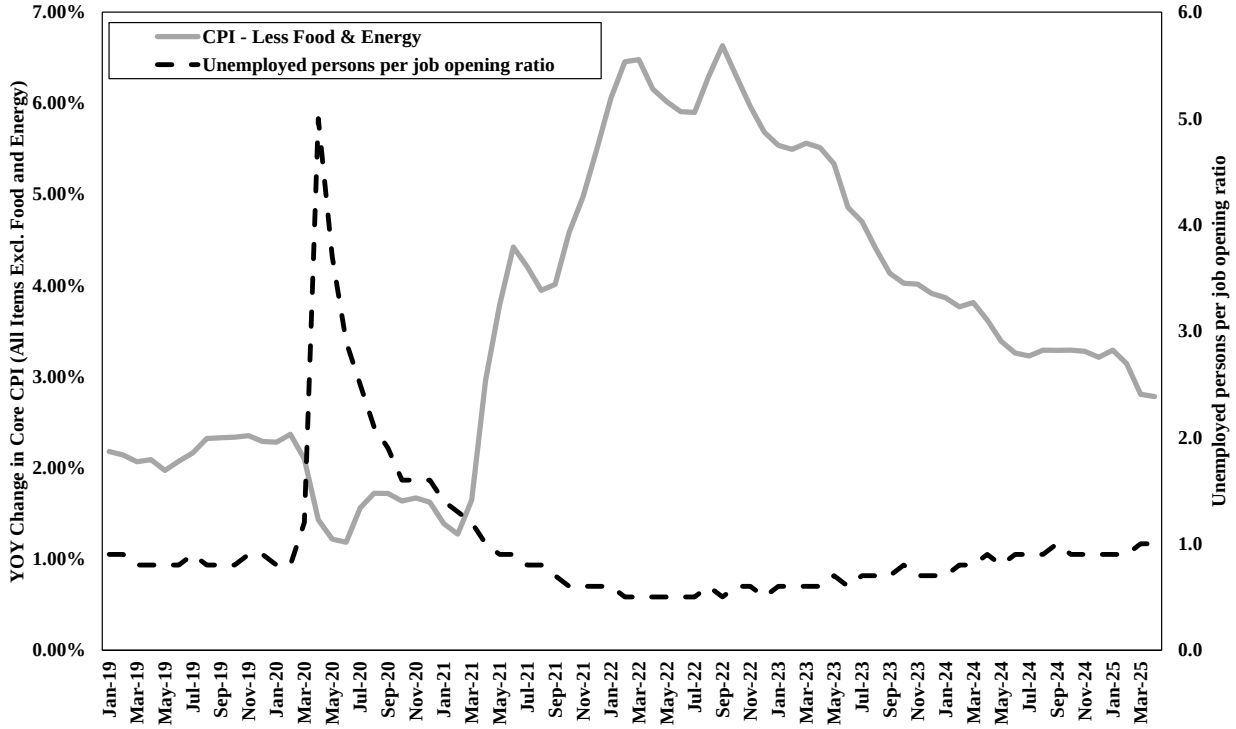
[6] St. Louis Federal Reserve Bank; Bureau of Labor Statistics; Public Service Commission of Wyoming, Docket No. 20004-117-ER-16, Memorandum Opinion, Findings, and Order Approving Stipulation, April 6, 2017.

[7] *Bloomberg*, Pickert, Reade, "Core US Inflation Rises to 40-Year High, Securing Big Fed Hike", October 13, 2022.

in response to the Federal Reserve's monetary policy, it continues to remain above the Federal Reserve's target level of 2.00 percent.

Because the Federal Reserve's dual mandate is to promote stable prices and employment, considering employment data, in addition to inflation, is important. The ratio of unemployed persons per job opening was 1.00 in April 2025 (the most recent data available at the time of this testimony) and has been consistently at or below 1.00 since April 2021, suggesting a tighter labor market. This indicates sustained strength in the labor market, allowing the Federal Reserve to prioritize reducing inflation by pursuing the necessary restrictive monetary policy needed to achieve its 2.00 percent target benchmark.

Figure 3: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to April 2025[8]



Q22. What policy actions did the Federal Reserve enact to respond to increased inflation?

A22. The dramatic increase in inflation 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. Between the March 2022 Federal Open Market Committee ("FOMC") meeting and the July 2023 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.

[8] Bureau of Labor Statistics; data available data as of June 3, 2025.

Q23. How did yields on long-term government bonds respond to the Federal Reserve's normalization of monetary policy?

A23. Since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds increased by over 350 basis points, increasing from 1.47 percent on December 15, 2021 to a peak of 4.98 percent in October 2023. It currently remains well above 2021 levels (*i.e.*, 4.41 percent as of May 30, 2025).[9]

Q24. Did the Federal Reserve recently reduce the federal funds rate?

A24. Yes. The Federal Reserve did recently reduce the federal funds rate by 50 basis points in September 2024, 25 basis points in November 2024, and 25 basis points in December 2024 noting at the September meeting the reduction was due to the risks associated with both inflation and the labor market becoming more balanced given the effectiveness of restrictive monetary policy in combatting inflation. However, the Federal Reserve left rates unchanged at the most recent FOMC meetings in January, March and May 2025.

Q25. What is the expected path of monetary policy over the near-term?

A25. At the May 2025 FOMC meeting, Chairman Powell noted that the economy is in a "solid position", the labor market is at or near "maximum employment" and inflation has declined "a great deal" but does still remain above the 2 percent long-term target.[10] As a result, the FOMC decided to maintain the current federal fund rate range of 4.25 percent to 4.50 percent.[11] Regarding the possible path of monetary policy, Chairman Powell acknowledged increased uncertainly due to the implementation of significant policy changes (*i.e.*, trade,

---

9 S&P Capital IQ Pro.

10 Transcript of Chair Powell's Press Conference, (May 7, 2025).

11 *Id.*

immigration, fiscal policy and regulation) by the Trump administration, in particular, the tariff increases which were much larger than expected and, if sustained, could lead to both higher inflation and increased unemployment.[12] However, Chairman Powell stated that monetary policy is well positioned to wait for greater clarity on the effects of the policy changes of the Trump Administration before considering any changes.[13] While the FOMC did not produce economic projections at the May 2025 meeting, the FOMC's forecast of the federal funds rate at the March 2025 meeting remained unchanged from the December 2024 meeting, forecasting just two rate cuts before the end of 2025.[14]

Q26. What has happened to the yields on long-term government bonds since the FOMC reduced the federal funds rate in September 2024?

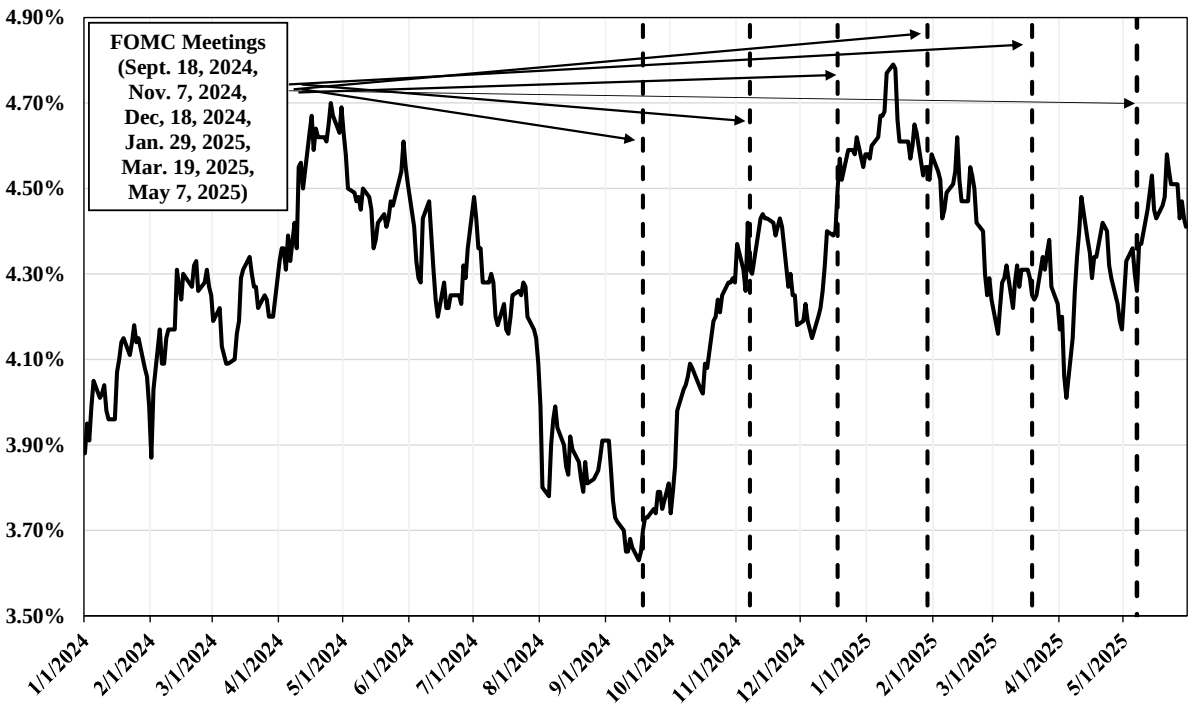
A26. As shown in Figure 4 below, while the yield on the 10-year treasury bond declined prior to the time of the first federal funds rate cut, the yield has increased since the September 2024 FOMC meeting. As of May 30, 2025, the 10-year Treasury bond yield was 4.41 percent, which is consistent with levels seen in June 2024, several months prior to the reductions in the federal funds rate.

[12] *Id.*

[13] *Id.*

[14] Federal Reserve, Summary of Economic Projections, March 19, 2025, at 2.

Figure 4: 10-Year Treasury Bond Yield, Janaury 2024 through May 30, 2025[15]



Q27. Why have long-term interest rates increased since the Federal Reserve reduced the federal funds rate in September?

A27. Investors view key elements of President Trump's economic plan, such as tax cuts, immigration policy, and tariffs, as inflationary. According to a *Reuters* article, the increase in long-term government bond yields was initially related to investors responding to an increasing probability of a Trump Administration in 2025 and has continued since President Trump's re-election and inauguration.[16] For example, on April 2, 2025, President Trump announced a significant set of tariffs on each of the U.S.'s trading partners, a policy initiative that is largely viewed as inflationary. Inflation affects bonds, in particular long-

[15] S&P Capital IQ Pro.

[16] Davide Barbuscia and Lewis Krauskopf, "Bond rebound uncertain as Trump plans overshadow Fed rate cuts," *Reuters*, November 8, 2024.

term government bonds, because it erodes the value of future bonds payments. Therefore, in an inflationary environment, investors will demand higher returns on bonds to compensate for the added risk of inflation thus bond prices decline and the yields on bonds increase. The longer the duration of the bond, the greater the effect of inflation which is why inflation risk is greater for long-term government bonds. The significant tariff policy increases the risk that inflation will remain elevated which is why the yields on long-term bonds have not decreased and in fact have increased since the Federal Reserve reduced the federal funds rate. Further, the use of tariffs strains the relationship with trading partners, which could result in a reduction in the foreign demand for long-term U.S. government bonds resulting in additional upward pressure on long-term government bond yields.[17]

Q28. What are expectations for the yields on long-term government bonds?

A28. Economists and analysts are expecting elevated rates. *Blue Chip Financial Forecasts* provides a forecast from economists on the 30-year Treasury bond. In the most recent published *Blue Chip Financial Forecasts* report, economists projected the 30-year treasury rate to remain relatively stable and decrease only slightly from 4.70 percent in Q3/2025 to 4.50 percent in Q3/2026.[18] Additionally, the consensus estimate over the longer-term (*i.e.,* 2027-2031) as also published in the most recent *Blue Chip Financial Forecasts* report was 4.40 percent.[19] This is important because it means that long-term interest rates are expected to remain elevated during the period that the Company's rates will be in effect.

---

[17] Vanjani, Karishma. "U.S. Treasury Bonds Sell Off as 30-Year Yield Rises Most Since 1982," *Barron's*, April 9, 2025.

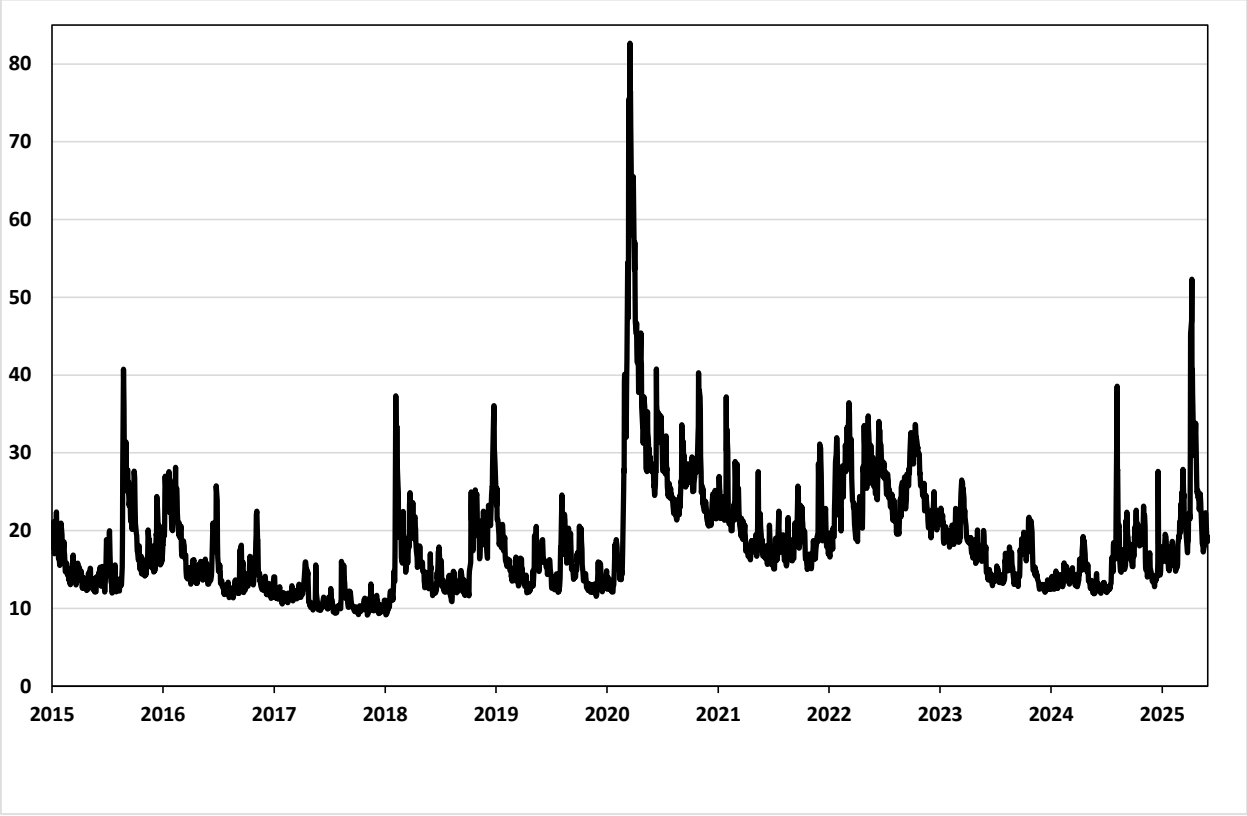
[18] *Blue Chip Financial Forecasts*, Vol. 44, No. 6, June 2, 2025, at 2.

[19] *Blue Chip Financial Forecasts*, Vol. 43, No. 6, June 2, 2025, at 14.

Q29. Has the recent Tariff Policy of the Trump Administration resulted in increased volatility in financial markets?

A29. Yes, financial markets have been extremely volatile since President Trump announced a significant set of tariffs on April 2, 2025. For example, as shown in Figure 5, the VIX, which measures investors' expectation of volatility in the S&P 500 over the next 30 days, peaked at 52.33 on April 8, 2025. The VIX has not reached 50.00 since April 2020 during the height of the COVID-19 pandemic. The high level of uncertainty associated with the economic effects of the Trump Administration's Tariff policy has resulted in significant volatility increasing the risk of holding equity investments and implying an increase in the cost of equity.

Figure 5: CBOE VIX – January 2015 – May 2025



Q30. Have you reviewed any other indicators that show uncertainty has increased as a result of the Trump Administration's Tariff Policy?

A30. Yes. In addition to the recent high volatility as measured by the VIX, the University of Michigan's consumer sentiment index indicates consumer sentiment is at its second lowest point since 1952 and that inflation expectations are at the highest levels in 44 years.[20] Furthermore, a recent Bank of America Global Fund Manager Survey conducted in April 2025, shows investor sentiment at its 5th lowest point since the study began in 2001.[21]

Q31. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A31. It is important to consider current and projected market conditions in setting the forward-looking ROE due to its effect on the estimated cost of equity. Long-term interest rates remain elevated and are expected to continue to remain elevated as a result of inflationary policies such as tariffs, immigration policy, and tax cuts. While the FOMC reduced the federal funds rate three times at the end of 2024, rates were unchanged at the first meetings of 2025 and Chairman Powell has indicated that the Federal Reserve is in wait and see mode and will rely on incoming data to determine when it is appropriate to adjust the federal funds rate. With higher expected interest rates, borrowing is more expensive which in turn raises the cost of capital. As a result, investors demand higher returns on equity, leading to an increase in the cost of equity.

---

[20] Harriet Torry. "'From anxious to petrified': Consumer sentiment plunges further," *Wall Street Journal*. April 11, 2025.

[21] Michael Hartnett et al., "Global Fund Manager Survey: The Bear Necessities," *BoA Global Research*. April 15, 2025.

V. PROXY GROUP SELECTION

Q32. Please provide a brief profile of Montana-Dakota.

A32. Montana-Dakota is a wholly owned subsidiary of MDU. The Company provides electric service to approximately 19,619 customers[22] in 6 communities in Wyoming.[23] As of December 31, 2024, the Company's net utility electric plant in Wyoming was approximately $112.51 million.[24] In addition, the Company had total electric sales in Wyoming in 2024 of approximately 292.77 million kWh.[25] Wyoming accounted for approximately 9.00 percent of MDU's total electric retail sales revenue in 2024.[26] Montana-Dakota Utilities Co. currently has an investment-grade long-term rating of BBB+ (Outlook: Stable) from S&P and BBB+ (Outlook: Stable) from Fitch.[27]

Q33. Why have you used a group of proxy companies to estimate the cost of equity for Montana-Dakota?

A33. In this proceeding, the cost of equity is being estimated for an electric 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.

---

22 Montana-Dakota, 2024 Annual Report to the Wyoming Public Service Commission, at 35.
23 Montana-Dakota Utilities Co., W.P.S.C Tariff No. 1, Electric Service, Effective Date January 1, 2019.
24 Montana-Dakota, 2024 Annual Report to the Wyoming Public Service Commission, at 7 and 13.
25 Montana-Dakota, 2024 Annual Report to the Wyoming Public Service Commission, at 35.
26 MDU Resources Group, Inc., Form 2024 SEC Form 10-K at 11.
27 S&P Global Ratings, and Fitch Ratings, as of May 6, 2025.

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.

Q34. How did you select the companies included in your proxy group?

A34. I began with the group of 35 companies that *Value Line* classifies as Electric 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;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- own regulated generation assets that are included in rate base;
- derive more than 40.00 percent of their megawatt-hour sales from their owned generation facilities;
- derive more than 60.00 percent of their total operating income from regulated electric operations; and
- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q35. What is the composition of your proxy group?

A35. 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
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Dominion Resources, Inc.	D
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

VI. COST OF EQUITY ESTIMATION

Q36. Please briefly discuss the ROE in the context of the regulated rate of return.

A36. 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.

Q37. How is the required cost of equity determined?

A37. 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.

Q38. What methods did you use to estimate the cost of equity for the Company in this proceeding?

A38. 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.

Q39. Is it important to use more than one analytical approach?

A39. 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.

Q40. Has the Commission recognized that it is important to consider the results of multiple ROE estimation models?

A40. Yes. It is my understanding, that in Docket No. 20000-198-ER-03 for PacifiCorp, the Commission emphasized that "[t]he determination of cost of capital in rate proceedings, as noted above, combines economic science, economic art and sound judgment as to what yields the most reasonable result."[30] Moreover, in Docket No. 20000-184-ER-02 for PacifiCorp, the Commission concluded that the ROE should not be set based on one specific model or a variation of a specific model and encouraged the evolution of economic thought be presented in future cases.[31]

---

[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.

[30] In the Application of PacifiCorp for a Retail Electric Utility Rate Increase of $41.8 Million Per Year, Docket No. 20000-ER-03-198 (Record No. 8310), Order at 11 (Feb. 28, 2004).

[31] In the Matter of the Application of PacifiCorp for Authority to Increase its Retail Electric Utility Service Rates in Wyoming, Consisting of a General Rate Increase of Approximately $30.7 Million Per Year, A Three-Year Rate Surcharge for Previous Power Costs to Recover $60.3 million, and an Additional Three-Year Surcharge to Recover Power Costs of $30.705 million related to the Hunter No. 1 Generating Unit, Docket No. 20000-ER-02-184 (Record No. 7475), Order at 78-79 (Mar. 6, 2003).

A. Constant Growth DCF Model

Q41. Please describe the DCF approach.

A41. 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:

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

Where P_0 represents the current stock price, D1…D∞ 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.

Q42. What assumptions are required for the constant growth DCF model?

A42. 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.

Q43. What market data did you use to calculate the dividend yield in your constant growth DCF model?

A43. 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 30, 2025.

Q44. Why did you use three averaging periods for stock prices?

A44. 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.

Q45. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A45. 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.

Q46. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A46. 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.

Q47. What sources of long-term growth rates did you rely on in your constant growth DCF model?

A47. My constant growth DCF model incorporates three sources of long-term projected EPS growth rates: (1) Zacks Investment Research (Zacks); (2) S&P Capital IQ; and (3) Value Line.

Q48. Have you previously relied on projected EPS growth rates provided by Yahoo! Finance?

A48. Yes, however, Yahoo! Finance no longer reports consensus projected 3- to 5-year EPS growth rates. As a result, I now instead rely on the consensus projected 3- to 5-year EPS growth rates reported by S&P Capital IQ.

Q49. How do you calculate the range of results for the constant growth DCF models?

A49. 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, S&P Capital IQ, 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.

Q50. Please summarize the results of your constant growth DCF analyses.

A50. 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	9.34%	10.45%	11.27%
90-Day Avg. Stock Price	9.39%	10.50%	11.31%
180-Day Avg. Stock Price	9.47%	10.59%	11.40%
Average	**9.40%**	**10.51%**	**11.33%**
Median Results:			

30-Day Avg. Stock Price	9.65%	10.25%	10.96%
90-Day Avg. Stock Price	9.71%	10.29%	11.06%
180-Day Avg. Stock Price	9.80%	10.46%	11.19%
Average	**9.72%**	**10.33%**	**11.07%**

B. CAPM Analysis

Q51. Please briefly describe the Capital Asset Pricing Model.

A51. 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.[32] 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:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market cost of equity;

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.

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

[32] 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.

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.

Q52. What risk-free rate did you use in your CAPM analyses?

A52. 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 4.86 percent;[33] (2) the average projected 30-year U.S. Treasury bond yield for the third quarter of 2025 through the third quarter of 2026, which is 4.60 percent;[34] and (3) the average projected 30-year U.S. Treasury bond yield for 2027 through 2031, which is 4.40 percent.[35]

Q53. What beta coefficients did you use in your CAPM analysis?

A53. 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

[33] Bloomberg Professional, as of May 30, 2025.

[34] *Blue Chip Financial Forecasts*, Vol. 44, No. 6, June 2, 2025, at 2.

[35] *Blue Chip Financial Forecasts*, Vol. 44, No. 6, June 2, 2025, at 14.

weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit No.___(AEB-2), Schedule 6, I also consider an additional CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group, which is calculated as an average of the Value Line beta coefficients for the companies in my proxy group from 2013 through 2024.

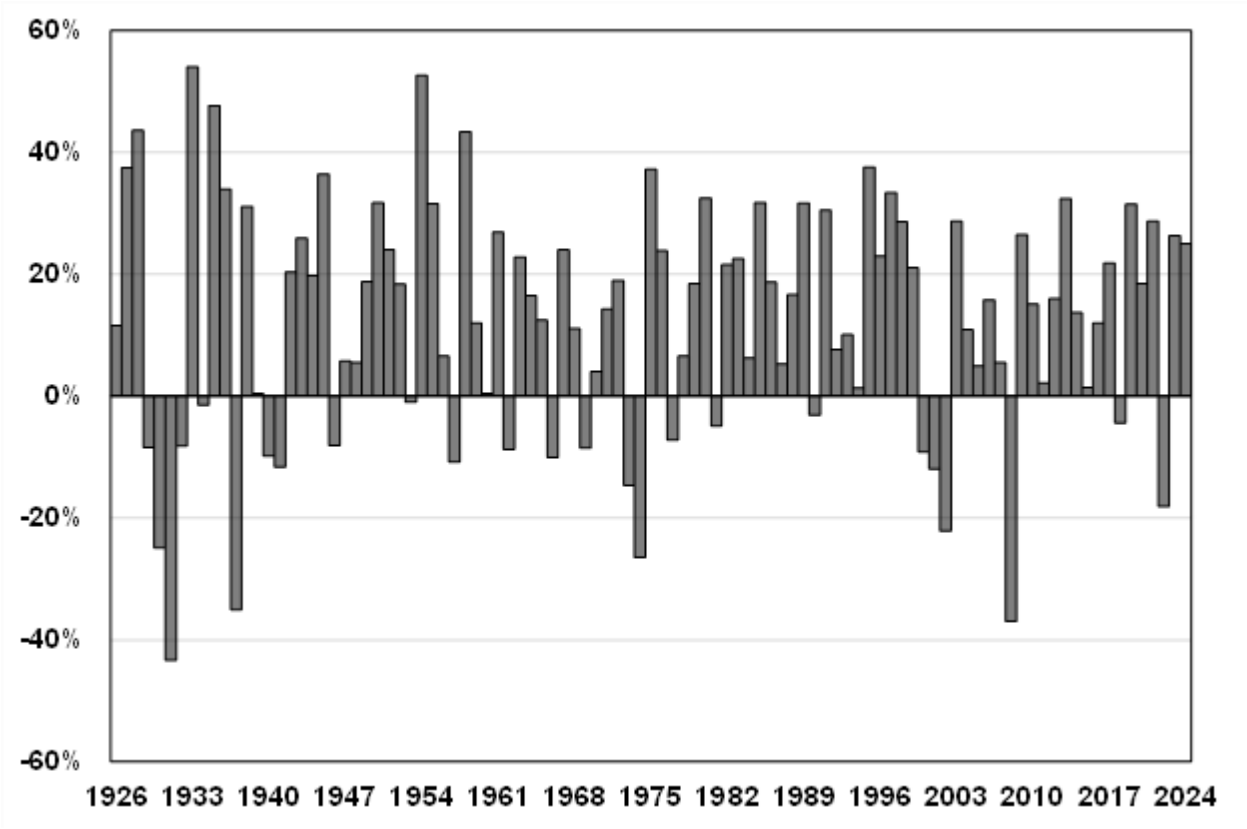
Q54. How do you estimate the market risk premium in the CAPM?

A54. 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 1.52 percent and a weighted long-term growth rate of 10.74 percent, the estimated required market return for the S&P 500 Index as of May 30, 2025 is 12.34 percent.

Q55. How does the expected market return compare to observed historical market returns?

A55. 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 12.34 percent is reasonable. In 53 out of the past 99 years (or approximately 54 percent of observations), the realized equity market return was at least 12.34 percent or greater.

Figure 8: Realized U.S. Equity Market Returns (1926–2024)[36]



Q56. Did you consider another form of the CAPM in your analysis?

A56. Yes. I also consider the results of an ECAPM in estimating the cost of equity for the Company.[37] 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 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:

[36] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook for 1926-2022 and from S&P Capital IQ Pro for 2023-2024.

[37] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., June 1, 2006, at 189.

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

Where:

k_e = the required market cost of equity;

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.[38]

Consistent with my CAPM, my application of the ECAPM uses the same three yields on the 30-year Treasury bonds as the risk-free rate, forward-looking market risk premium estimates, and beta coefficients.

Q57. What are the results of your CAPM and ECAPM analyses?

A57. The results of my CAPM and ECAPM analyses are summarized in Figure 9, as well as presented in Exhibit No.___(AEB-2), Schedule 5.

[38] *Id.*, at 191.

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	11.26%	11.22%	11.19%
Current Bloomberg Beta	10.56%	10.50%	10.45%
Long-term Avg. *Value Line* Beta	10.68%	10.62%	10.57%
ECAPM:			
Current *Value Line* Beta	11.53%	11.50%	11.48%
Current Bloomberg Beta	11.01%	10.96%	10.92%
Long-term Avg. *Value Line* Beta	11.09%	11.05%	11.01%

C. BYRP Analysis

Q58. Please describe your Bond Yield Risk Premium ("BYRP") analysis.

A58. 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 vertically integrated electric utilities as the historical measure of the cost of equity to determine the risk premium.

Q59. What is the fundamental relationship between the equity risk premium and interest rates?

A59. Both academic literature and market evidence indicates 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.[39]

Q60. Is the BYRP analysis relevant to investors?

A60. 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. Because my BYRP analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

Q61. What did your BYRP analysis reveal?

A61. As shown in Figure 10, from January 1980 through May 2025, 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:

---

[39] *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.

$$RP = a + b(T) \qquad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

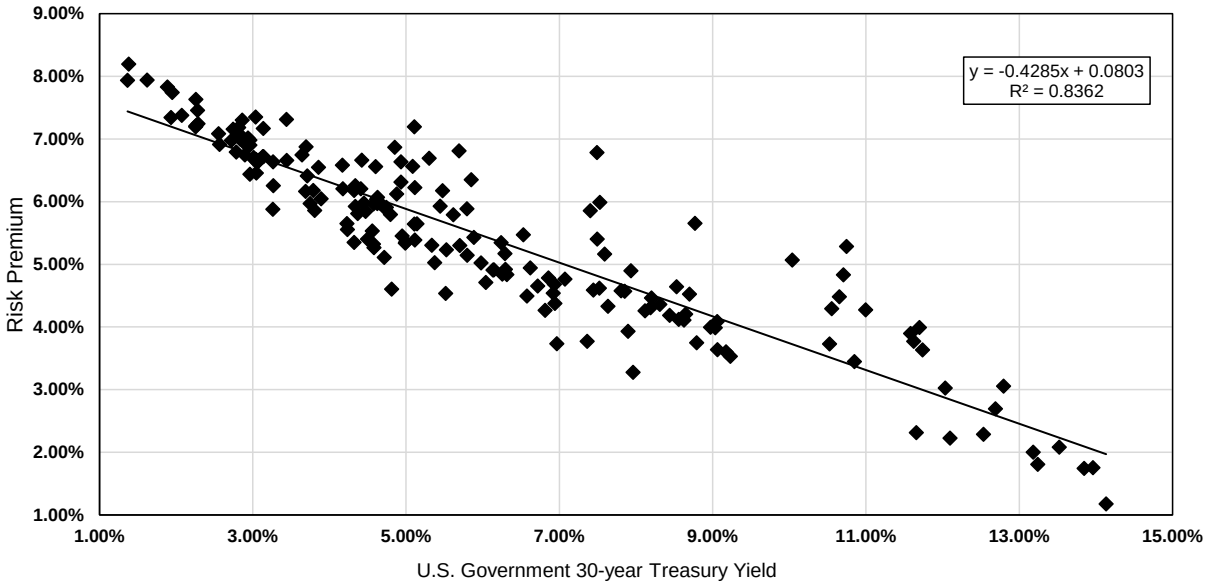
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs were derived from the vertically integrated electric utility rate cases over this period as reported by Regulatory Research Associates ("RRA").[40] The equation's coefficients are statistically significant at the 99.00 percent level.

[40] The data was screened to eliminate limited issue rider cases, transmission-only cases, distribution-only cases and cases that were silent with respect to the authorized ROE.

Figure 10: Risk Premium Regression Analysis



Q62. What are the results of your BYRP analysis?

A62. 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	10.80%	10.65%	10.54%

Q63. How did the results of the BYRP inform your recommended ROE for Montana-Dakota?

A63. I consider 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 vertically integrated utilities across the U.S.

VII. REGULATORY AND BUSINESS RISKS

Q64. Do the results of the cost of equity analyses alone provide an appropriate estimate of the cost of equity for the Company?

A64. 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

Q65. Is there a risk to a firm associated with small size?

A65. 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.[41]

[41] Michael Annin, "Equity and the Small-Stock Effect," *Public Utilities Fortnightly*, October 15, 1995.

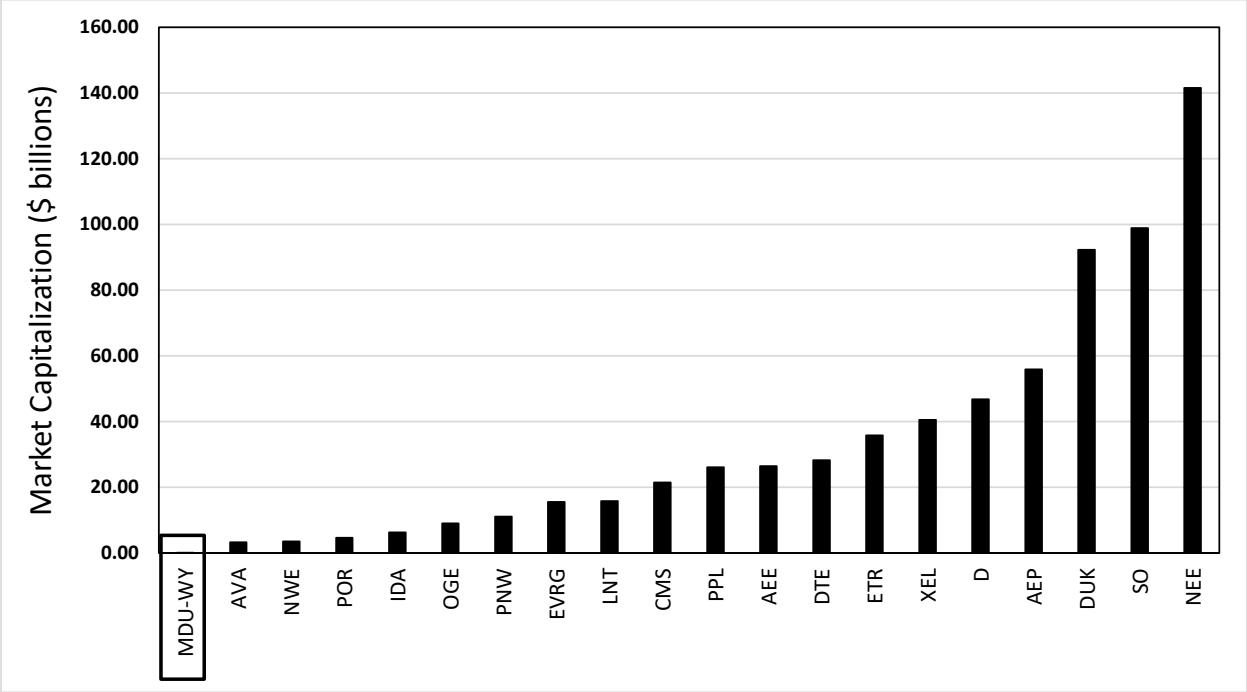
Q66. How does the smaller size of a utility affect its business risk?

A66. 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.

Q67. How does Montana-Dakota's electric operations in Wyoming compare in size to the companies in the proxy group companies?

A67. Comparing the common equity of Montana-Dakota's electric operations in Wyoming to the proxy group demonstrates that Montana-Dakota is substantially smaller than the median of the proxy group. Exhibit No.___(AEB-2), Schedule 9 provides the actual market capitalization for the proxy group companies and estimates the common equity for Montana-Dakota (*i.e.,* the implied market capitalization if Montana-Dakota's electric service operations in Wyoming were a stand-alone publicly-traded entity). Figure 12 below shows that the common equity for Montana-Dakota's electric operations in Wyoming is the lowest, and far below, any of the proxy group companies.

Figure 12: Market Capitalization of the Proxy Group Companies and the Common Equity of Montana-Dakota[42]



Q68. How did you estimate the size premium for Montana-Dakota?

A68. 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 $26.12 billion, which corresponds to the second decile of Kroll's market capitalization data.[44] Based on Kroll's analysis, that decile corresponds to a size premium of 0.33 percent (*i.e.*, 33 basis points). In comparison, Montana-Dakota's common equity of approximately $51.69 million falls within the tenth decile, which corresponds to a size

[42] To estimate the size of the Company relative to the proxy group, I calculated the equity balance of Montana-Dakota's capital structure of $51.69 million by multiplying the Company's test year rate base by the Company's proposed common equity ratio of 51.085 percent.

[43] Kroll, Cost of Capital Navigator – Size Premium: Annual data as of 12/31/2024.

[44] *Id*.

premium of 4.47 percent (*i.e.*, 447 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 414 basis points (*i.e.*, 4.47 percent minus 0.33 percent).

Q69. Have utility companies been included in the Kroll size premium study conducted?

A69. 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]

Q70. Is the size premium applicable to companies in regulated industries such as utilities?

A70. 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 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]

---

[45] *Kroll*, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

[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*.

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]

Q71. Have regulators in other jurisdictions made a specific risk adjustment to the cost of equity results based on a company's small size?

A71. 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 "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 its substantial

---

[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.*

[50] Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at 37.

[51] *Id.*, at 32 and 37.

transmission assets, 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]

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]

---

[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 (May 1, 2017) at 55.

[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

Q72. How have you considered the smaller size of Montana-Dakota in your recommendation of the Company's ROE in this proceeding?

A72. 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 consider the small size of Montana-Dakota's electric operations in Wyoming, 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. All else equal, the additional risk associated with the Company's small size supports an ROE toward the upper end of the range of results from the cost of equity estimation models.

B. Flotation Cost

Q73. What are flotation costs?

A73. 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.

Q74. Why is it important to consider flotation costs in the allowed ROE?

A74. 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.

---

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).

Q75. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A75. 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.

Q76. Can you provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested?

A76. Yes. Suppose MDU issues stock with a value of $100, and an equity investor invests $100 in MDU 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 ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU 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.

Q77. Is the need to consider flotation costs eliminated because Montana-Dakota is a wholly-owned subsidiary of MDU?

A77. 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.

Q78. Is the need to consider flotation costs recognized by the academic and financial communities?

A78. 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.

Q79. How did you calculate the flotation costs for MDU?

A79. My flotation cost calculation is based on the costs of issuing equity that were incurred by MDU in its two most recent common equity issuances. 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 impact on the proxy group's cost of equity amounts to 14 basis points (i.e., 0.14 percent) based on the median and 14 basis points (i.e., 0.14 percent) based on the mean.

Q80. Do your final cost of equity results include an adjustment for flotation cost recovery?

A80. No, I did not make an explicit adjustment for flotation costs to any of the quantitative results of my cost of equity models. Rather, I considered the incremental cost associated with stock issuance as part of my overall recommendations regarding the range of reasonable ROEs and ultimate recommended ROE.

C. Capital Expenditures

Q81. What are the Company's projected capital expenditure requirements over the next few years?

A81. As of December 31, 2024, the Company had net utility plant of approximately $112.51 million[57], and the Company currently projects capital expenditures for 2025 through 2029 of approximately $69.48 million,[58] which represent approximately 61.75 percent of its current net utility plant.

---

[57] Montana-Dakota, 2024 Annual Report to the Wyoming Public Service Commission, at 7 and 13.

[58] Data provided by the Company.

Q82. How do Montana-Dakota's capital expenditure requirements compare to those of the proxy group companies?

A82. 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 2025 through 2029 by its total net utility plant as of December 31, 2024. As shown, Montana-Dakota's ratio of capital expenditures as a percentage of net utility plant is slightly greater than the median for the proxy group companies of 54.99 percent.

Q83. How is the Company's risk profile affected by its substantial capital expenditure requirements?

A83. 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.

Q84. Do credit rating agencies recognize the risks associated with significant capital expenditures?

A84. 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.[59]

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:

> We expect rising capital spending and increasing cash flow deficits that are not sufficiently funded in a credit-supportive manner will continue to pressure the industry's financial performance. Its average funds from operations (FFO) to debt was about 15% in 2021 and has gradually fallen to about 13.5%, primarily reflecting rising leverage (see chart 20). Given our expectations for continued increasing capital spending over the next decade, we expect financial performance and credit quality will continue to be pressured. [60]

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.

---

[59] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

[60] S&P Global Ratings, "Industry Credit Outlook 2025, North American Regulated Utilities: Capex and climate change pressures credit quality," January 14, 2025, at 10.

Q85. Does the Company currently have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A85. No. However, in the current proceeding, Montana-Dakota is requesting approval of a Reliability and Safety Infrastructure Rider ("RSIR"), which would allow for the recovery of specific investments related to the improvement of reliability, the replacement of pre-1985 underground distribution cables, and upgrades necessary for wildfire mitigation. Although, it is important to note that if approved the Company would only recovers a portion of its capital costs through the RSIR and thus would still rely on rate case filings for capital cost recovery.

Q86. Are capital investment recovery mechanisms common amongst electric utilities?

A86. Yes. 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. Therefore, if approved, the RSIR would not provide any incremental risk mitigation for the financial risks associated with capital expenditures relative to the proxy group. However, absent approval of the RSIR, Montana-Dakota would have greater risk from a capital expenditure standpoint than the proxy group companies.

Q87. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A87. The Company's capital expenditure requirements as a percentage of net utility plant are meaningful and are expected to continue over the next few years. Additionally, if the RSIR is approved, similar to a number of the operating subsidiaries of the proxy group, Montana-Dakota would have a capital tracking mechanism to recover some of the Company's projected capital expenditure. However, absent approval of the RSIR, the Company's risk

regarding the timely recovery of capital expenditures would increase significantly relative to the proxy group.

D. Regulatory Risk

Q88. How does the regulatory environment affect investors' risk assessments?

A88. 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.

Q89. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A89. 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.[61]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "we assess regulatory advantage because the influence of the regulatory framework and regime is of critical importance. It defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[62] 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)

[61] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 2.

[62] Standard & Poor's Global Ratings, "Sector-Specific Corporate Methodology," April 4, 2024, at 147.

tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[63]

Q90. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A90. 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, "[u]tility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the regulatory framework is a key determinant of the credit quality of a utility."[64] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[t]he regulatory framework is important because it provides the basis for decisions that affect utilities, including rate-setting as well as the consistency and predictability of regulatory decision-making."[65]

Q91. 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?

A91. Yes. I have evaluated the regulatory framework in Wyoming 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

---

[63] *Id.*

[64] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 8.

[65] *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 Wyoming, while approximately 52 percent of the utility operating subsidiaries of the companies in the proxy group 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.[66]

Volumetric Risk: Montana-Dakota has partial protection against volumetric risk in Wyoming through customer and demand charges that recover a majority of the Company's fixed cost. By comparison, approximately 61 percent of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed

[66] 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.

variable rate design that allow them to break the link between customer usage and revenues.

Capital Cost Recovery: While Montana-Dakota does not currently have a capital tracking mechanism to recover capital investment costs between rate cases, the Company is requesting approval of the RSIR which would allow Montana-Dakota to recover a portion of its projected capital investments between rate cases. As noted previously, approximately 71 percent of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism.

Q92. What is the effect of Montana-Dakota having relatively fewer timely cost recovery mechanisms?

A92. The lack of timely cost recovery mechanisms can result in regulatory lag. Regulatory lag occurs when a regulated utility is not able to recover its just and reasonable costs of providing service to customers on a timely basis. Regulatory lag is reflected in a utility's financial performance through earnings attrition, which is the inability of the utility to earn its authorized ROE due to delays in the recovery of allowable costs that have been incurred to provide regulated service to customers.

Q93. Is there evidence that Montana-Dakota has been unable to earn its authorized ROE?

A93. Yes. As shown in Figure 13, Montana-Dakota's electric operations in Wyoming has significantly under-earned its authorized ROE in four of the last five years. Over the last five years, the average earned ROE on the Company's electric operations in Wyoming was 6.96 percent, as compared with the average authorized ROE of 9.45 percent, for an average under-earning of 249 basis points per year. Further, comparing the Company's actual

earned equity return in 2024 to the yield on the 30-year Treasury bond of 4.86 percent shown in Figure 2, demonstrates that the earned return to equity investors is currently well below the return on risk-free investments.

Figure 13: Montana-Dakota's Earned vs. Authorized ROE (2020-2024)

	Earned ROE	Authorized ROE	Earnings Differential (bps)
2020	9.50%	9.45%	0.05%
2021	8.33%	9.45%	-1.12%
2022	8.48%	9.45%	-0.97%
2023	4.98%	9.45%	-4.47%
2024	3.49%	9.45%	-5.96%
Average	**6.96%**	**9.45%**	**-2.49%**

Q94. What are your conclusions regarding the perceived risks related to the regulatory environment in Wyoming?

A94. 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 cost recovery between rate proceedings than Montana-Dakota has in Wyoming. Moreover, the Company has significantly under-earned its authorized ROE in four of the last five years. As a result, I conclude, that if the Company's proposed RSIR is approved, Montana-Dakota would have slightly greater than average regulatory risk relative to the proxy group.

Finally, while my analysis assumes that the Company's proposed RSIR will be approved, it is important to note that the regulatory risk of Montana-Dakota relative to the proxy group would increase if the Commission does not approve the Company's proposal.

VIII. CAPITAL STRUCTURE

Q95. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A95. Yes, it is. The equity ratio is the primary indicator of financial risk for a regulated utility such as Montana-Dakota. Assuming other factors equal, a higher debt ratio increases the risk to equity investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, 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. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q96. What is the Company's proposed capital structure?

A96. The Company proposes to establish a capital structure consisting of 51.085 percent common equity, 45.274 percent long-term debt, and 3.641 percent short-term debt.

Q97. Do you conduct any analysis to determine if this requested equity ratio was reasonable?

A97. Yes. I compare 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, short-term debt and preferred equity for the most recent eight quarters for each of the utility operating subsidiaries of the proxy group companies. As shown on Exhibit No.___(AEB-2), Schedule 13, the common equity ratios for operating subsidiaries of the proxy group companies range from 45.33 percent to 58.67 percent, with an average of 51.35 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 consistent with the average.

Q98. Are there other factors to be considered in setting the Company's capital structure?

A98. 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, Moody's recently maintained its "stable" 2025 outlook for the regulated gas and electric utilities sector on the expectation of continued regulatory support, which includes supportive legislature, timely recovery of excess purchased power costs, and weather-related cost recovery. Moody's "stable" rating also considers its expectation for declining interest rates and inflation, as well as favorable natural gas prices. Moody's

makes clear that constructive regulatory outcomes that promote timely cost recovery is the key factor in supporting utility credit quality.[67]

S&P continues to maintain a negative outlook for the utility industry, noting that downgrades have outpaced upgrades for the fifth consecutive year and the most common investor-owned utility credit rating is a "BBB+".[68] S&P expects the industry to have increased cash flow deficits as a result of significant capital spending.[69] Weak common equity issuance contributes pressure to the industry's financial health. The utility industry will need ongoing access to capital markets to fund the capital expenditures. Furthermore, S&P also notes that there is a significant increase physical risk due to climate change and elevated wildfire risk.

Fitch Ratings ("Fitch") has a "neutral" outlook for the utility industry noting that moderation in inflation and "subdued" commodity costs have eased pressures on customer bills. However, Fitch cautions that utility capital expenditures are expected to grow at a "double-digit rate" and thus, rate case outcomes will be key to watch as regulators balance rate requests and customer bill pressures.[70]

The credit ratings agencies' continued concerns over increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the Company in the context of this proceeding.

---

[67] Moody's Investors Service, Outlook. "Outlook Stable; regulatory support, economic factors offset financial pressure." November 7, 2024

[68] S&P Global Ratings. Industry Credit Outlook 2025, "North American Regulated Utilities: Capex and climate change pressure credit quality." January 14, 2025

[69] *Id*.

[70] Fitch Ratings, "North American Utilities, Power & Gas Outlook 2025," December 5, 2024, at 1

Q99. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A99. 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.

It also is important to realize that because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-run 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. Consequently, both the ROE and capital structure are very important to debt and equity investors. Furthermore, considering the capital market conditions discussed in Section IV, the authorized ROE and capital structure take on even greater significance.

Q100. What is your conclusion regarding an appropriate equity ratio for Montana-Dakota?

A100. Considering the actual capital structures of the utility operating subsidiaries of the proxy group, I believe that the Company's proposed common equity ratio of 51.085 percent is reasonable. The proposed equity ratio is well within the range of equity ratios established by the capital structures of the utility operating subsidiaries of the proxy companies.

IX. CONCLUSION AND RECOMMENDATION

Q101. What is your conclusion regarding a fair ROE for Montana-Dakota?

A101.

A102. Figure 14 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.

Figure 14: Summary of Analytical Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.34%	10.45%	11.27%
90-Day Avg. Stock Price	9.39%	10.50%	11.31%
180-Day Avg. Stock Price	9.47%	10.59%	11.40%
Average	9.40%	10.51%	11.33%
Median Results:			
30-Day Avg. Stock Price	9.65%	10.25%	10.96%
90-Day Avg. Stock Price	9.71%	10.29%	11.06%
180-Day Avg. Stock Price	9.80%	10.46%	11.19%
Average	9.72%	10.33%	11.07%

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	11.26%	11.22%	11.19%
Current Bloomberg Beta	10.56%	10.50%	10.45%
Long-term Avg. *Value Line* Beta	10.68%	10.62%	10.57%
ECAPM:			
Current *Value Line* Beta	11.53%	11.50%	11.48%
Current Bloomberg Beta	11.01%	10.96%	10.92%
Long-term Avg. *Value Line* Beta	11.09%	11.05%	11.01%
Bond Yield Risk Premium	10.80%	10.65%	10.54%

Q102. What is your conclusion regarding the Company's proposed capital structure?

A103. The Company's proposed capital structure consisting of 51.085 percent common equity, 45.274 percent long-term debt, and 3.641 percent short-term debt is reasonable when compared to the capital structures of the companies in the proxy group.

Q103. Does this conclude you direct testimony?

A104. 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.

Brattle

BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Gas	11/24	UNS Gas	Docket No. G-04204A-24-0237	Return on Equity
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				
Pacific Gas & Electric Company	03/25	Pacific Gas & Electric Company	25-03-010	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
PacifiCorp, d/b/a Pacific Power	05/22	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				
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				
United Illuminating	11/24	United Illuminating	Docket No. 24-10-04	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
Intermountain Gas Co	05/25	Intermountain Gas Co	C-INT-G-25-02	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/24	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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				
MidAmerican Energy Company	02/25	MidAmerican Energy Company	Docket No. RPU-2025-0001	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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	01/25	Evergy Kansas	Docket No. 25-EKCE-294-RTS	Return on Equity
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	04/25	Kentucky American Water Company	Docket No. 2025-____	Return on Equity
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
Consumers Energy	12/16/24	Consumers Energy	C-U-21806	Return on Equity
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
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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				
Ameren Missouri	09/24	Ameren Missouri	File No. GR-2024-0369	Return on Equity
Missouri American Water Company	07/24	Missouri American Water Company	WR-2024-0320	Return on Equity
Ameren Missouri	06/24	Ameren Missouri	File No. ER-2024-0319	Return on Equity
Evergy Missouri West	02/24	Evergy Missouri West	File No. ER-2024-0189	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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.	7/24	Montana-Dakota Utilities Co.	D2024-05-061	Return on Equity
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
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				
Nevada Power Company d/b/a NV Energy	02/25	Nevada Power Company d/b/a NV Energy	25-02016	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
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				
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	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				
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
Montana-Dakota Utilities Co.	08/23	Montana-Dakota Utilities Co.	Docket No. EL23-020	Return on Equity
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
Tennessee Public Utility Commission				
Tennessee American Water Company	04/24	Tennessee American Water Company	Docket No.24-00032	Return on Equity
Texas Public Utility Commission				
Sharyland Utilities, L.L.C.	05/25	Sharyland Utilities, L.L.C.	Docket No. 57994	Return on Equity
Electric Transmission Texas LLC	02/25	Electric Transmission Texas LLC	Docket No. 57518	Return on Equity
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	06/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 24-035-04	Return on Equity
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
West Virginia American Water Company	05/25	West Virginia American Water Company	Case No. 25-____-W-42T	Return on Equity
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
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				
Montana-Dakota Utilities Co.	10/24	Montana-Dakota Utilities Co.	Docket No. 30013-415-GR-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	08/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-671-ER-24	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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	9.34%	10.45%	11.27%
90-Day Avg. Stock Price	9.39%	10.50%	11.31%
180-Day Avg. Stock Price	9.47%	10.59%	11.40%
Average	9.40%	10.51%	11.33%
Median Results:			
30-Day Avg. Stock Price	9.65%	10.25%	10.96%
90-Day Avg. Stock Price	9.71%	10.29%	11.06%
180-Day Avg. Stock Price	9.80%	10.46%	11.19%
Average	9.72%	10.33%	11.07%

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	11.26%	11.22%	11.19%
Current Bloomberg Beta	10.56%	10.50%	10.45%
Long-term Avg. *Value Line* Beta	10.68%	10.62%	10.57%
ECAPM:			
Current *Value Line* Beta	11.53%	11.50%	11.48%
Current Bloomberg Beta	11.01%	10.96%	10.92%
Long-term Avg. *Value Line* Beta	11.09%	11.05%	11.01%
Bond Yield Risk Premium	10.80%	10.65%	10.54%

PROXY GROUP SCREENING DATA AND RESULTS

Company	Ticker	[1] Dividends	[2] S&P Credit Rating Between BBB- and AAA	[3] Positive Growth Rates from at least two sources (S&P Capital IQ, Value Line, and Zacks)	[4] Generation Assets Included in Rate Base	[5] Net Generation as a % of Total Sales > 40%	[6] Regulated Elec. Operating Income / Total Operating Income > 60%	[7] Announced Merger
Alliant Energy Corporation	LNT	Yes	BBB+	Yes	Yes	75.72%	86.94%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	72.83%	84.42%	No
American Electric Power Company, Inc.	AEP	Yes	BBB+	Yes	Yes	52.31%	99.09%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	60.28%	74.40%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	46.65%	64.34%	No
Dominion Resources, Inc.	D	Yes	BBB+	Yes	Yes	78.55%	96.93%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	84.17%	65.78%	No
Duke Energy Corporation	DUK	Yes	BBB+	Yes	Yes	80.86%	90.04%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	71.73%	96.44%	No
Evergy, Inc.	EVRG	Yes	BBB+	Yes	Yes	60.85%	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	62.48%	99.99%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	96.37%	83.75%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	57.78%	85.96%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	45.23%	100.00%	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	Yes	72.64%	100.00%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	54.70%	100.00%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	41.64%	94.19%	No
Southern Company	SO	Yes	A-	Yes	Yes	76.55%	77.26%	No
Xcel Energy Inc.	XEL	Yes	BBB+	Yes	Yes	58.13%	85.62%	No

Notes:
[1] Bloomberg Professional
[2] Bloomberg Professional
[3] S&P Capital IQ, Value Line Investment Survey, and Zacks
[4] S&P Capital IQ Pro
[5] S&P Capital IQ Pro
[6] Form 10-K's for 2024, 2023, and 2022
[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	Zacks Projected EPS Growth Rate	S&P Capital IQ 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
Alliant Energy Corporation	LNT	$2.03	$61.19	3.32%	3.42%	6.00%	6.60%	6.54%	6.38%	9.42%	9.80%	10.03%
Ameren Corporation	AEE	$2.84	$97.64	2.91%	3.01%	6.50%	7.00%	6.95%	6.82%	9.50%	9.82%	10.01%
American Electric Power Company, Inc.	AEP	$3.72	$104.28	3.57%	3.68%	6.50%	6.40%	6.80%	6.57%	10.08%	10.25%	10.49%
Avista Corporation	AVA	$1.96	$39.73	4.93%	5.08%	5.50%	6.10%	5.98%	5.86%	10.57%	10.94%	11.18%
CMS Energy Corporation	CMS	$2.17	$71.46	3.04%	3.14%	6.00%	7.80%	7.31%	7.04%	9.13%	10.18%	10.96%
Dominion Resources, Inc.	D	$2.67	$54.27	4.92%	5.17%	6.00%	13.60%	11.39%	10.33%	11.07%	15.50%	18.85%
DTE Energy Company	DTE	$4.36	$135.92	3.21%	3.31%	4.50%	7.60%	7.62%	6.57%	7.78%	9.89%	10.95%
Duke Energy Corporation	DUK	$4.18	$117.97	3.54%	3.65%	6.00%	6.30%	6.38%	6.23%	9.65%	9.88%	10.04%
Entergy Corporation	ETR	$2.40	$82.84	2.90%	3.00%	3.00%	9.50%	9.12%	7.21%	5.94%	10.21%	12.53%
Evergy, Inc.	EVRG	$2.67	$66.71	4.00%	4.13%	7.50%	5.70%	5.70%	6.30%	9.82%	10.43%	11.65%
IDACORP, Inc.	IDA	$3.44	$115.84	2.97%	3.08%	6.00%	8.10%	8.09%	7.40%	9.06%	10.48%	11.19%
NextEra Energy, Inc.	NEE	$2.27	$68.19	3.32%	3.46%	8.50%	7.70%	7.81%	8.00%	11.15%	11.46%	11.96%
NorthWestern Corporation	NWE	$2.64	$56.85	4.64%	4.78%	4.50%	6.90%	5.80%	5.73%	9.25%	10.51%	11.70%
OGE Energy Corporation	OGE	$1.69	$44.56	3.78%	3.90%	6.50%	6.30%	6.53%	6.44%	10.20%	10.35%	10.44%
Pinnacle West Capital Corporation	PNW	$3.58	$92.11	3.89%	3.96%	5.00%	2.10%	4.76%	3.95%	6.03%	7.92%	8.98%
Portland General Electric Company	POR	$2.00	$42.29	4.73%	4.84%	6.50%	3.40%	4.76%	4.89%	8.21%	9.73%	11.38%
PPL Corporation	PPL	$1.09	$35.34	3.08%	3.20%	7.50%	7.50%	7.40%	7.47%	10.60%	10.67%	10.70%
Southern Company	SO	$2.96	$89.40	3.31%	3.42%	6.50%	6.50%	6.29%	6.43%	9.70%	9.85%	9.92%
Xcel Energy Inc.	XEL	$2.28	$70.26	3.25%	3.37%	7.00%	7.50%	7.73%	7.41%	10.36%	10.78%	11.10%
Mean				3.65%	3.77%	6.08%	6.98%	7.00%	6.69%	9.34%	10.45%	11.27%
Median				3.32%	3.46%	6.00%	6.90%	6.80%	6.57%	9.65%	10.25%	10.96%

Notes:
[1] Bloomberg Professional as of May 30, 2025
[2] Bloomberg Professional 30-day average as of May 30, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[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

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Zacks Projected EPS Growth Rate	[7] S&P Capital IQ Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity: Minimum Growth Rate	[10] Cost of Equity: Mean Growth Rate	[11] Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.03	$61.21	3.32%	3.42%	6.00%	6.60%	6.54%	6.38%	9.42%	9.80%	10.03%
Ameren Corporation	AEE	$2.84	$97.49	2.91%	3.01%	6.50%	7.00%	6.95%	6.82%	9.51%	9.83%	10.02%
American Electric Power Company, Inc.	AEP	$3.72	$103.05	3.61%	3.73%	6.50%	6.40%	6.80%	6.57%	10.13%	10.29%	10.53%
Avista Corporation	AVA	$1.96	$38.73	5.06%	5.21%	5.50%	6.10%	5.98%	5.86%	10.70%	11.07%	11.32%
CMS Energy Corporation	CMS	$2.17	$70.76	3.07%	3.17%	6.00%	7.80%	7.31%	7.04%	9.16%	10.21%	10.99%
Dominion Resources, Inc.	D	$2.67	$54.00	4.94%	5.20%	6.00%	13.60%	11.39%	10.33%	11.09%	15.53%	18.88%
DTE Energy Company	DTE	$4.36	$131.49	3.32%	3.42%	4.50%	7.60%	7.62%	6.57%	7.89%	10.00%	11.06%
Duke Energy Corporation	DUK	$4.18	$115.97	3.60%	3.72%	6.00%	6.30%	6.38%	6.23%	9.71%	9.94%	10.10%
Entergy Corporation	ETR	$2.40	$82.57	2.91%	3.01%	3.00%	9.50%	9.12%	7.21%	5.95%	10.22%	12.54%
Evergy, Inc.	EVRG	$2.67	$65.90	4.05%	4.18%	7.50%	5.70%	5.70%	6.30%	9.87%	10.48%	11.70%
IDACORP, Inc.	IDA	$3.44	$113.78	3.02%	3.14%	6.00%	8.10%	8.09%	7.40%	9.11%	10.53%	11.25%
NextEra Energy, Inc.	NEE	$2.27	$68.92	3.29%	3.42%	8.50%	7.70%	7.81%	8.00%	11.11%	11.42%	11.93%
NorthWestern Corporation	NWE	$2.64	$55.47	4.76%	4.90%	4.50%	6.90%	5.80%	5.73%	9.37%	10.63%	11.82%
OGE Energy Corporation	OGE	$1.69	$44.03	3.83%	3.95%	6.50%	6.30%	6.53%	6.44%	10.25%	10.39%	10.48%
Pinnacle West Capital Corporation	PNW	$3.58	$90.66	3.95%	4.03%	5.00%	2.10%	4.76%	3.95%	6.09%	7.98%	9.05%
Portland General Electric Company	POR	$2.00	$42.58	4.70%	4.81%	6.50%	3.40%	4.76%	4.89%	8.18%	9.70%	11.35%
PPL Corporation	PPL	$1.09	$34.64	3.15%	3.26%	7.50%	7.50%	7.40%	7.47%	10.66%	10.73%	10.77%
Southern Company	SO	$2.96	$87.86	3.37%	3.48%	6.50%	6.50%	6.29%	6.43%	9.76%	9.91%	9.98%
Xcel Energy Inc.	XEL	$2.28	$69.08	3.30%	3.42%	7.00%	7.50%	7.73%	7.41%	10.42%	10.83%	11.16%
Mean				3.69%	3.81%	6.08%	6.98%	7.00%	6.69%	9.39%	10.50%	11.31%
Median				3.37%	3.48%	6.00%	6.90%	6.80%	6.57%	9.71%	10.29%	11.06%

Notes:
[1] Bloomberg Professional as of May 30, 2025
[2] Bloomberg Professional 90-day average as of May 30, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[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	Zacks Projected EPS Growth Rate	S&P Capital IQ 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
Alliant Energy Corporation	LNT	$2.03	$60.06	3.38%	3.49%	6.00%	6.60%	6.54%	6.38%	9.48%	9.87%	10.09%
Ameren Corporation	AEE	$2.84	$92.69	3.06%	3.17%	6.50%	7.00%	6.95%	6.82%	9.66%	9.99%	10.17%
American Electric Power Company, Inc.	AEP	$3.72	$99.08	3.75%	3.88%	6.50%	6.40%	6.80%	6.57%	10.27%	10.44%	10.68%
Avista Corporation	AVA	$1.96	$37.52	5.22%	5.38%	5.50%	6.10%	5.98%	5.86%	10.87%	11.24%	11.48%
CMS Energy Corporation	CMS	$2.17	$69.06	3.14%	3.25%	6.00%	7.80%	7.31%	7.04%	9.24%	10.29%	11.06%
Dominion Resources, Inc.	D	$2.67	$54.52	4.90%	5.15%	6.00%	13.60%	11.39%	10.33%	11.04%	15.48%	18.83%
DTE Energy Company	DTE	$4.36	$126.51	3.45%	3.56%	4.50%	7.60%	7.62%	6.57%	8.02%	10.13%	11.19%
Duke Energy Corporation	DUK	$4.18	$113.18	3.69%	3.81%	6.00%	6.30%	6.38%	6.23%	9.80%	10.04%	10.19%
Entergy Corporation	ETR	$2.40	$76.50	3.14%	3.25%	3.00%	9.50%	9.12%	7.21%	6.18%	10.46%	12.79%
Evergy, Inc.	EVRG	$2.67	$63.02	4.24%	4.37%	7.50%	5.70%	5.70%	6.30%	10.06%	10.67%	11.90%
IDACORP, Inc.	IDA	$3.44	$110.23	3.12%	3.24%	6.00%	8.10%	8.09%	7.40%	9.21%	10.63%	11.35%
NextEra Energy, Inc.	NEE	$2.27	$72.51	3.13%	3.25%	8.50%	7.70%	7.81%	8.00%	10.95%	11.25%	11.76%
NorthWestern Corporation	NWE	$2.64	$54.40	4.85%	4.99%	4.50%	6.90%	5.80%	5.73%	9.46%	10.72%	11.92%
OGE Energy Corporation	OGE	$1.69	$42.30	3.98%	4.11%	6.50%	6.30%	6.53%	6.44%	10.41%	10.56%	10.64%
Pinnacle West Capital Corporation	PNW	$3.58	$88.42	4.05%	4.13%	5.00%	2.10%	4.76%	3.95%	6.19%	8.08%	9.15%
Portland General Electric Company	POR	$2.00	$43.87	4.56%	4.67%	6.50%	3.40%	4.76%	4.89%	8.04%	9.56%	11.21%
PPL Corporation	PPL	$1.09	$33.49	3.25%	3.38%	7.50%	7.50%	7.40%	7.47%	10.77%	10.84%	10.88%
Southern Company	SO	$2.96	$86.66	3.42%	3.53%	6.50%	6.50%	6.29%	6.43%	9.81%	9.95%	10.03%
Xcel Energy Inc.	XEL	$2.28	$67.24	3.39%	3.52%	7.00%	7.50%	7.73%	7.41%	10.51%	10.93%	11.25%
Mean				3.78%	3.90%	6.08%	6.98%	7.00%	6.69%	9.47%	10.59%	11.40%
Median				3.45%	3.56%	6.00%	6.90%	6.80%	6.57%	9.80%	10.46%	11.19%

Notes:
[1] Bloomberg Professional as of May 30, 2025
[2] Bloomberg Professional 180-day average as of May 30, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.86%	0.95	12.34%	7.48%	11.97%	12.06%
Ameren Corporation	AEE	4.86%	0.90	12.34%	7.48%	11.59%	11.78%
American Electric Power Company, Inc.	AEP	4.86%	0.85	12.34%	7.48%	11.22%	11.50%
Avista Corporation	AVA	4.86%	0.75	12.34%	7.48%	10.47%	10.94%
CMS Energy Corporation	CMS	4.86%	0.90	12.34%	7.48%	11.59%	11.78%
Dominion Resources, Inc.	D	4.86%	0.75	12.34%	7.48%	10.47%	10.94%
DTE Energy Company	DTE	4.86%	1.00	12.34%	7.48%	12.34%	12.34%
Duke Energy Corporation	DUK	4.86%	0.70	12.34%	7.48%	10.10%	10.66%
Entergy Corporation	ETR	4.86%	1.00	12.34%	7.48%	12.34%	12.34%
Evergy, Inc.	EVRG	4.86%	0.95	12.34%	7.48%	11.97%	12.06%
IDACORP, Inc.	IDA	4.86%	0.75	12.34%	7.48%	10.47%	10.94%
NextEra Energy, Inc.	NEE	4.86%	0.90	12.34%	7.48%	11.59%	11.78%
NorthWestern Corporation	NWE	4.86%	0.80	12.34%	7.48%	10.85%	11.22%
OGE Energy Corporation	OGE	4.86%	1.05	12.34%	7.48%	12.71%	12.62%
Pinnacle West Capital Corporation	PNW	4.86%	0.80	12.34%	7.48%	10.85%	11.22%
Portland General Electric Company	POR	4.86%	0.80	12.34%	7.48%	10.85%	11.22%
PPL Corporation	PPL	4.86%	0.90	12.34%	7.48%	11.59%	11.78%
Southern Company	SO	4.86%	0.75	12.34%	7.48%	10.47%	10.94%
Xcel Energy Inc.	XEL	4.86%	0.75	12.34%	7.48%	10.47%	10.94%
Mean						11.26%	11.53%
Median						11.22%	11.50%

Notes:
[1] Bloomberg Professional 30-day average as of May 30, 2025
[2] Value Line
[3] Exhibit No. ___(AEB-2), Schedule 7
[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.60%	0.95	12.34%	7.74%	11.95%	12.05%
Ameren Corporation	AEE	4.60%	0.90	12.34%	7.74%	11.57%	11.76%
American Electric Power Company, Inc.	AEP	4.60%	0.85	12.34%	7.74%	11.18%	11.47%
Avista Corporation	AVA	4.60%	0.75	12.34%	7.74%	10.41%	10.89%
CMS Energy Corporation	CMS	4.60%	0.90	12.34%	7.74%	11.57%	11.76%
Dominion Resources, Inc.	D	4.60%	0.75	12.34%	7.74%	10.41%	10.89%
DTE Energy Company	DTE	4.60%	1.00	12.34%	7.74%	12.34%	12.34%
Duke Energy Corporation	DUK	4.60%	0.70	12.34%	7.74%	10.02%	10.60%
Entergy Corporation	ETR	4.60%	1.00	12.34%	7.74%	12.34%	12.34%
Evergy, Inc.	EVRG	4.60%	0.95	12.34%	7.74%	11.95%	12.05%
IDACORP, Inc.	IDA	4.60%	0.75	12.34%	7.74%	10.41%	10.89%
NextEra Energy, Inc.	NEE	4.60%	0.90	12.34%	7.74%	11.57%	11.76%
NorthWestern Corporation	NWE	4.60%	0.80	12.34%	7.74%	10.79%	11.18%
OGE Energy Corporation	OGE	4.60%	1.05	12.34%	7.74%	12.73%	12.63%
Pinnacle West Capital Corporation	PNW	4.60%	0.80	12.34%	7.74%	10.79%	11.18%
Portland General Electric Company	POR	4.60%	0.80	12.34%	7.74%	10.79%	11.18%
PPL Corporation	PPL	4.60%	0.90	12.34%	7.74%	11.57%	11.76%
Southern Company	SO	4.60%	0.75	12.34%	7.74%	10.41%	10.89%
Xcel Energy Inc.	XEL	4.60%	0.75	12.34%	7.74%	10.41%	10.89%
Mean						11.22%	11.50%
Median						11.18%	11.47%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 2
[2] Value Line
[3] Exhibit No. ___(AEB-2), Schedule 7
[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.40%	0.95	12.34%	7.94%	11.94%	12.04%
Ameren Corporation	AEE	4.40%	0.90	12.34%	7.94%	11.55%	11.75%
American Electric Power Company, Inc.	AEP	4.40%	0.85	12.34%	7.94%	11.15%	11.45%
Avista Corporation	AVA	4.40%	0.75	12.34%	7.94%	10.36%	10.85%
CMS Energy Corporation	CMS	4.40%	0.90	12.34%	7.94%	11.55%	11.75%
Dominion Resources, Inc.	D	4.40%	0.75	12.34%	7.94%	10.36%	10.85%
DTE Energy Company	DTE	4.40%	1.00	12.34%	7.94%	12.34%	12.34%
Duke Energy Corporation	DUK	4.40%	0.70	12.34%	7.94%	9.96%	10.55%
Entergy Corporation	ETR	4.40%	1.00	12.34%	7.94%	12.34%	12.34%
Evergy, Inc.	EVRG	4.40%	0.95	12.34%	7.94%	11.94%	12.04%
IDACORP, Inc.	IDA	4.40%	0.75	12.34%	7.94%	10.36%	10.85%
NextEra Energy, Inc.	NEE	4.40%	0.90	12.34%	7.94%	11.55%	11.75%
NorthWestern Corporation	NWE	4.40%	0.80	12.34%	7.94%	10.75%	11.15%
OGE Energy Corporation	OGE	4.40%	1.05	12.34%	7.94%	12.74%	12.64%
Pinnacle West Capital Corporation	PNW	4.40%	0.80	12.34%	7.94%	10.75%	11.15%
Portland General Electric Company	POR	4.40%	0.80	12.34%	7.94%	10.75%	11.15%
PPL Corporation	PPL	4.40%	0.90	12.34%	7.94%	11.55%	11.75%
Southern Company	SO	4.40%	0.75	12.34%	7.94%	10.36%	10.85%
Xcel Energy Inc.	XEL	4.40%	0.75	12.34%	7.94%	10.36%	10.85%
Mean						11.19%	11.48%
Median						11.15%	11.45%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14

[2] Value Line

[3] Exhibit No. ___(AEB-2), Schedule 7

[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.86%	0.75	12.34%	7.48%	10.47%	10.93%
Ameren Corporation	AEE	4.86%	0.72	12.34%	7.48%	10.26%	10.78%
American Electric Power Company, Inc.	AEP	4.86%	0.71	12.34%	7.48%	10.16%	10.71%
Avista Corporation	AVA	4.86%	0.71	12.34%	7.48%	10.17%	10.71%
CMS Energy Corporation	CMS	4.86%	0.70	12.34%	7.48%	10.09%	10.65%
Dominion Resources, Inc.	D	4.86%	0.68	12.34%	7.48%	9.92%	10.52%
DTE Energy Company	DTE	4.86%	0.77	12.34%	7.48%	10.66%	11.08%
Duke Energy Corporation	DUK	4.86%	0.68	12.34%	7.48%	9.93%	10.53%
Entergy Corporation	ETR	4.86%	0.84	12.34%	7.48%	11.11%	11.42%
Evergy, Inc.	EVRG	4.86%	0.75	12.34%	7.48%	10.47%	10.94%
IDACORP, Inc.	IDA	4.86%	0.74	12.34%	7.48%	10.41%	10.89%
NextEra Energy, Inc.	NEE	4.86%	0.88	12.34%	7.48%	11.47%	11.68%
NorthWestern Corporation	NWE	4.86%	0.82	12.34%	7.48%	11.00%	11.33%
OGE Energy Corporation	OGE	4.86%	0.87	12.34%	7.48%	11.39%	11.63%
Pinnacle West Capital Corporation	PNW	4.86%	0.78	12.34%	7.48%	10.72%	11.13%
Portland General Electric Company	POR	4.86%	0.74	12.34%	7.48%	10.42%	10.90%
PPL Corporation	PPL	4.86%	0.89	12.34%	7.48%	11.51%	11.72%
Southern Company	SO	4.86%	0.74	12.34%	7.48%	10.37%	10.86%
Xcel Energy Inc.	XEL	4.86%	0.71	12.34%	7.48%	10.14%	10.69%
Mean						10.56%	11.01%
Median						10.42%	10.90%

Notes:
[1] Bloomberg Professional 30-day average as of May 30, 2025
[2] Bloomberg Professional
[3] Exhibit No. ___(AEB-2), Schedule 7
[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.60%	0.75	12.34%	7.74%	10.40%	10.88%
Ameren Corporation	AEE	4.60%	0.72	12.34%	7.74%	10.18%	10.72%
American Electric Power Company, Inc.	AEP	4.60%	0.71	12.34%	7.74%	10.09%	10.65%
Avista Corporation	AVA	4.60%	0.71	12.34%	7.74%	10.09%	10.65%
CMS Energy Corporation	CMS	4.60%	0.70	12.34%	7.74%	10.01%	10.59%
Dominion Resources, Inc.	D	4.60%	0.68	12.34%	7.74%	9.83%	10.46%
DTE Energy Company	DTE	4.60%	0.77	12.34%	7.74%	10.60%	11.03%
Duke Energy Corporation	DUK	4.60%	0.68	12.34%	7.74%	9.85%	10.47%
Entergy Corporation	ETR	4.60%	0.84	12.34%	7.74%	11.07%	11.39%
Evergy, Inc.	EVRG	4.60%	0.75	12.34%	7.74%	10.40%	10.89%
IDACORP, Inc.	IDA	4.60%	0.74	12.34%	7.74%	10.34%	10.84%
NextEra Energy, Inc.	NEE	4.60%	0.88	12.34%	7.74%	11.44%	11.66%
NorthWestern Corporation	NWE	4.60%	0.82	12.34%	7.74%	10.95%	11.30%
OGE Energy Corporation	OGE	4.60%	0.87	12.34%	7.74%	11.36%	11.60%
Pinnacle West Capital Corporation	PNW	4.60%	0.78	12.34%	7.74%	10.67%	11.08%
Portland General Electric Company	POR	4.60%	0.74	12.34%	7.74%	10.35%	10.85%
PPL Corporation	PPL	4.60%	0.89	12.34%	7.74%	11.48%	11.70%
Southern Company	SO	4.60%	0.74	12.34%	7.74%	10.30%	10.81%
Xcel Energy Inc.	XEL	4.60%	0.71	12.34%	7.74%	10.06%	10.63%
Mean						10.50%	10.96%
Median						10.35%	10.85%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 2

[2] Bloomberg Professional

[3] Exhibit No. ___(AEB-2), Schedule 7

[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.40%	0.75	12.34%	7.94%	10.35%	10.85%
Ameren Corporation	AEE	4.40%	0.72	12.34%	7.94%	10.13%	10.68%
American Electric Power Company, Inc.	AEP	4.40%	0.71	12.34%	7.94%	10.03%	10.61%
Avista Corporation	AVA	4.40%	0.71	12.34%	7.94%	10.03%	10.61%
CMS Energy Corporation	CMS	4.40%	0.70	12.34%	7.94%	9.95%	10.55%
Dominion Resources, Inc.	D	4.40%	0.68	12.34%	7.94%	9.77%	10.41%
DTE Energy Company	DTE	4.40%	0.77	12.34%	7.94%	10.55%	11.00%
Duke Energy Corporation	DUK	4.40%	0.68	12.34%	7.94%	9.78%	10.42%
Entergy Corporation	ETR	4.40%	0.84	12.34%	7.94%	11.04%	11.36%
Evergy, Inc.	EVRG	4.40%	0.75	12.34%	7.94%	10.35%	10.85%
IDACORP, Inc.	IDA	4.40%	0.74	12.34%	7.94%	10.29%	10.80%
NextEra Energy, Inc.	NEE	4.40%	0.88	12.34%	7.94%	11.41%	11.64%
NorthWestern Corporation	NWE	4.40%	0.82	12.34%	7.94%	10.91%	11.27%
OGE Energy Corporation	OGE	4.40%	0.87	12.34%	7.94%	11.33%	11.58%
Pinnacle West Capital Corporation	PNW	4.40%	0.78	12.34%	7.94%	10.62%	11.05%
Portland General Electric Company	POR	4.40%	0.74	12.34%	7.94%	10.30%	10.81%
PPL Corporation	PPL	4.40%	0.89	12.34%	7.94%	11.46%	11.68%
Southern Company	SO	4.40%	0.74	12.34%	7.94%	10.25%	10.77%
Xcel Energy Inc.	XEL	4.40%	0.71	12.34%	7.94%	10.00%	10.59%
Mean						10.45%	10.92%
Median						10.30%	10.81%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14

[2] Bloomberg Professional

[3] Exhibit No. ___(AEB-2), Schedule 7

[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.86%	0.78	12.34%	7.48%	10.66%	11.08%
Ameren Corporation	AEE	4.86%	0.75	12.34%	7.48%	10.50%	10.96%
American Electric Power Company, Inc.	AEP	4.86%	0.70	12.34%	7.48%	10.07%	10.64%
Avista Corporation	AVA	4.86%	0.81	12.34%	7.48%	10.91%	11.27%
CMS Energy Corporation	CMS	4.86%	0.72	12.34%	7.48%	10.22%	10.75%
Dominion Resources, Inc.	D	4.86%	0.73	12.34%	7.48%	10.35%	10.85%
DTE Energy Company	DTE	4.86%	0.79	12.34%	7.48%	10.78%	11.17%
Duke Energy Corporation	DUK	4.86%	0.70	12.34%	7.48%	10.13%	10.68%
Entergy Corporation	ETR	4.86%	0.78	12.34%	7.48%	10.72%	11.13%
Evergy, Inc.	EVRG	4.86%	0.94	12.34%	7.48%	11.89%	12.00%
IDACORP, Inc.	IDA	4.86%	0.75	12.34%	7.48%	10.47%	10.94%
NextEra Energy, Inc.	NEE	4.86%	0.78	12.34%	7.48%	10.69%	11.10%
NorthWestern Corporation	NWE	4.86%	0.78	12.34%	7.48%	10.72%	11.13%
OGE Energy Corporation	OGE	4.86%	0.95	12.34%	7.48%	12.00%	12.08%
Pinnacle West Capital Corporation	PNW	4.86%	0.77	12.34%	7.48%	10.63%	11.06%
Portland General Electric Company	POR	4.86%	0.78	12.34%	7.48%	10.69%	11.10%
PPL Corporation	PPL	4.86%	0.86	12.34%	7.48%	11.28%	11.55%
Southern Company	SO	4.86%	0.70	12.34%	7.48%	10.13%	10.68%
Xcel Energy Inc.	XEL	4.86%	0.69	12.34%	7.48%	10.00%	10.59%
Mean						10.68%	11.09%
Median						10.66%	11.08%

Notes:

[1] Bloomberg Professional 30-day average as of May 30, 2025

[2] Exhibit No. ___(AEB-2), Schedule 6

[3] Exhibit No. ___(AEB-2), Schedule 7

[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.60%	0.78	12.34%	7.74%	10.60%	11.03%
Ameren Corporation	AEE	4.60%	0.75	12.34%	7.74%	10.44%	10.91%
American Electric Power Company, Inc.	AEP	4.60%	0.70	12.34%	7.74%	9.99%	10.57%
Avista Corporation	AVA	4.60%	0.81	12.34%	7.74%	10.86%	11.23%
CMS Energy Corporation	CMS	4.60%	0.72	12.34%	7.74%	10.15%	10.70%
Dominion Resources, Inc.	D	4.60%	0.73	12.34%	7.74%	10.28%	10.79%
DTE Energy Company	DTE	4.60%	0.79	12.34%	7.74%	10.73%	11.13%
Duke Energy Corporation	DUK	4.60%	0.70	12.34%	7.74%	10.05%	10.62%
Entergy Corporation	ETR	4.60%	0.78	12.34%	7.74%	10.66%	11.08%
Evergy, Inc.	EVRG	4.60%	0.94	12.34%	7.74%	11.88%	11.99%
IDACORP, Inc.	IDA	4.60%	0.75	12.34%	7.74%	10.41%	10.89%
NextEra Energy, Inc.	NEE	4.60%	0.78	12.34%	7.74%	10.63%	11.06%
NorthWestern Corporation	NWE	4.60%	0.78	12.34%	7.74%	10.66%	11.08%
OGE Energy Corporation	OGE	4.60%	0.95	12.34%	7.74%	11.99%	12.07%
Pinnacle West Capital Corporation	PNW	4.60%	0.77	12.34%	7.74%	10.57%	11.01%
Portland General Electric Company	POR	4.60%	0.78	12.34%	7.74%	10.63%	11.06%
PPL Corporation	PPL	4.60%	0.86	12.34%	7.74%	11.24%	11.52%
Southern Company	SO	4.60%	0.70	12.34%	7.74%	10.05%	10.62%
Xcel Energy Inc.	XEL	4.60%	0.69	12.34%	7.74%	9.92%	10.53%
Mean						10.62%	11.05%
Median						10.60%	11.03%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 2

[2] Exhibit No. ___(AEB-2), Schedule 6

[3] Exhibit No. ___(AEB-2), Schedule 7

[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.40%	0.78	12.34%	7.94%	10.55%	11.00%
Ameren Corporation	AEE	4.40%	0.75	12.34%	7.94%	10.39%	10.88%
American Electric Power Company, Inc.	AEP	4.40%	0.70	12.34%	7.94%	9.93%	10.53%
Avista Corporation	AVA	4.40%	0.81	12.34%	7.94%	10.82%	11.20%
CMS Energy Corporation	CMS	4.40%	0.72	12.34%	7.94%	10.09%	10.65%
Dominion Resources, Inc.	D	4.40%	0.73	12.34%	7.94%	10.22%	10.75%
DTE Energy Company	DTE	4.40%	0.79	12.34%	7.94%	10.69%	11.10%
Duke Energy Corporation	DUK	4.40%	0.70	12.34%	7.94%	9.99%	10.58%
Entergy Corporation	ETR	4.40%	0.78	12.34%	7.94%	10.62%	11.05%
Evergy, Inc.	EVRG	4.40%	0.94	12.34%	7.94%	11.86%	11.98%
IDACORP, Inc.	IDA	4.40%	0.75	12.34%	7.94%	10.36%	10.85%
NextEra Energy, Inc.	NEE	4.40%	0.78	12.34%	7.94%	10.59%	11.03%
NorthWestern Corporation	NWE	4.40%	0.78	12.34%	7.94%	10.62%	11.05%
OGE Energy Corporation	OGE	4.40%	0.95	12.34%	7.94%	11.98%	12.07%
Pinnacle West Capital Corporation	PNW	4.40%	0.77	12.34%	7.94%	10.52%	10.98%
Portland General Electric Company	POR	4.40%	0.78	12.34%	7.94%	10.59%	11.03%
PPL Corporation	PPL	4.40%	0.86	12.34%	7.94%	11.22%	11.50%
Southern Company	SO	4.40%	0.70	12.34%	7.94%	9.99%	10.58%
Xcel Energy Inc.	XEL	4.40%	0.69	12.34%	7.94%	9.86%	10.48%
Mean						10.57%	11.01%
Median						10.55%	11.00%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14

[2] Exhibit No. ___(AEB-2), Schedule 6

[3] Exhibit No. ___(AEB-2), Schedule 7

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

Company	Ticker	[1] 12/31/2013	[2] 12/31/2014	[3] 12/31/2015	[4] 12/31/2016	[5] 12/31/2017	[6] 12/31/2018	[7] 12/31/2019	[8] 12/31/2020	[9] 12/31/2021	[10] 12/31/2022	[11] 12/31/2023	[12] 12/31/2024	[13] Average
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.85	0.90	0.90	0.78
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.90	0.90	0.75
American Electric Power Company, Inc.	AEP	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.75	0.80	0.80	0.70
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.90	0.95	0.81
CMS Energy Corporation	CMS	0.70	0.70	0.75	0.65	0.65	0.55	0.50	0.80	0.80	0.80	0.85	0.85	0.72
Dominion Resources, Inc.	D	0.70	0.70	0.70	0.65	0.65	0.60	0.55	0.80	0.85	0.85	0.85	0.90	0.73
DTE Energy Company	DTE	0.80	0.75	0.75	0.65	0.65	0.55	0.55	0.95	0.95	0.95	0.95	1.00	0.79
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.85	0.90	0.90	0.70
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.95	0.95	1.00	0.78
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.90	0.95	0.94
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.80	0.85	0.85	0.75
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.95	1.00	1.05	0.78
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.55	0.60	0.95	0.95	0.90	0.95	1.00	0.78
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	1.00	1.05	1.10	0.95
Pinnacle West Capital Corporation	PNW	0.75	0.70	0.75	0.70	0.70	0.55	0.50	0.90	0.90	0.90	0.95	0.95	0.77
Portland General Electric Company	POR	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0.90	0.85	0.90	0.95	0.78
PPL Corporation	PPL	0.65	0.60	0.70	0.70	0.75	0.70	0.70	1.15	1.10	1.05	1.10	1.10	0.86
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.90	0.95	0.95	0.70
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.85	0.85	0.69
Mean		0.72	0.72	0.74	0.68	0.68	0.58	0.57	0.90	0.90	0.88	0.92	0.94	0.78

Notes:

[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Value Line, Dated December 29, 2023.
[12] Value Line, Dated December 27, 2024.
[13] Average ([1] - [12])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.52%
[2] Estimate of the S&P 500 Growth Rate	10.74%
[3] S&P 500 Estimated Required Market Return	12.34%

		[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	321.40001	59.44	19,104.02	0.05%	9.22%	0.00%	6.30%	0.00%
American Express Co	AXP	700.58887	264.81	185,522.94	0.51%	1.24%	0.01%	14.67%	0.07%
Verizon Communications Inc	VZ	4216.25491	41.91	176,703.24	0.48%	6.47%	0.03%	2.62%	0.01%
Texas Pacific Land Corp	TPL	22.9848	1334.63	30,676.20		0.48%			
Broadcom Inc	AVGO	4701.94872	192.31	904,231.76		1.23%		23.48%	
Boeing Co/The	BA	754.00547	177.95	134,175.27				31.75%	
Solventum Corp	SOLV	173.00293	66.07	11,430.30				-0.25%	
Caterpillar Inc	CAT	477.93202	306.45	146,462.27	0.40%	1.84%	0.01%	3.10%	0.01%
JPMorgan Chase & Co	JPM	2782.99629	243.55	677,798.75	1.85%	2.30%	0.04%	6.34%	0.12%
Chevron Corp	CVX	1746.71926	138.73	242,322.36	0.66%	4.93%	0.03%	11.58%	0.08%
Coca-Cola Co/The	KO	4303.56681	71.91	309,469.49	0.84%	2.84%	0.02%	5.69%	0.05%
AbbVie Inc	ABBV	1768.97828	186.06	329,136.10	0.90%	3.53%	0.03%	12.90%	0.12%
Walt Disney Co/The	DIS	1807.78887	90.28	163,207.18	0.44%	1.11%	0.00%	12.81%	0.06%
Corpay Inc	CPAY	70.24992	322.03	22,622.58	0.06%			11.99%	0.01%
Extra Space Storage Inc	EXR	212.22535	141.05	29,934.39	0.08%	4.59%	0.00%	3.10%	0.00%
Exxon Mobil Corp	XOM	4325.29365	108.57	469,597.13	1.28%	3.65%	0.05%	11.37%	0.15%
Phillips 66	PSX	407.43724	103.97	42,361.25		4.62%		25.92%	
General Electric Co	GE	1066.38664	198.43	211,603.10	0.58%	0.73%	0.00%	18.48%	0.11%
HP Inc	HPQ	942.70303	25.28	23,831.53		4.58%			
Home Depot Inc/The	HD	993.92816	357.58	355,408.83	0.97%	2.57%	0.02%	5.00%	0.05%
Monolithic Power Systems Inc	MPWR	47.87735	583.72	27,946.97		1.07%			
International Business Machines Corp	IBM	929.39658	232.41	216,001.06	0.59%	2.89%	0.02%	3.70%	0.02%
Johnson & Johnson	JNJ	2406.07328	154.58	371,930.81	1.01%	3.36%	0.03%	7.00%	0.07%
Lululemon Athletica Inc	LULU	115.52123	267.9	30,948.14					
McDonald's Corp	MCD	715.07212	316.74	226,491.94	0.62%	2.24%	0.01%	8.40%	0.05%
Merck & Co Inc	MRK	2516.39413	82.74	208,206.45	0.57%	3.92%	0.02%	14.62%	0.08%
3M Co	MMM	538.18136	137.32	73,903.06	0.20%	2.13%	0.00%	6.18%	0.01%
American Water Works Co Inc	AWK	195.01095	143.97	28,075.73	0.08%	2.30%	0.00%	8.00%	0.01%
Bank of America Corp	BAC	7602.79833	39.69	301,755.07		2.62%			
Pfizer Inc	PFE	5671.45477	22.92	129,989.74	0.35%	7.50%	0.03%	0.85%	0.00%
Procter & Gamble Co/The	PG	2344.54203	161.02	377,518.16	1.03%	2.63%	0.03%	3.76%	0.04%
AT&T Inc	T	7178.183	26.81	192,447.09	0.52%	4.14%	0.02%	3.95%	0.02%
Travelers Cos Inc/The	TRV	226.56879	259.16	58,717.57	0.16%	1.70%	0.00%	2.44%	0.00%
RTX Corp	RTX	1335.95377	125.22	167,288.13	0.46%	2.17%	0.01%	7.41%	0.03%
Analog Devices Inc	ADI	495.97648	194.59	96,512.06	0.26%	2.04%	0.01%	16.72%	0.04%
Walmart Inc	WMT	8000.88691	95.09	760,804.34	2.07%	0.99%	0.02%	8.01%	0.17%
Cisco Systems Inc	CSCO	3978.29243	56.71	225,608.96	0.61%	2.89%	0.02%	5.02%	0.03%
Intel Corp	INTC	4362	20.05	87,458.10	0.24%			15.96%	0.04%
General Motors Co	GM	966.28049	47.11	45,521.47	0.12%	1.27%	0.00%	0.47%	0.00%
Microsoft Corp	MSFT	7433.98223	391.85	2,913,005.94	7.93%	0.85%	0.07%	13.38%	1.06%
Dollar General Corp	DG	219.94708	93.56	20,578.25	0.06%	2.52%	0.00%	5.74%	0.00%
Cigna Group/The	CI	271.1081	335.36	90,918.81	0.25%	1.80%	0.00%	10.86%	0.03%
Kinder Morgan Inc	KMI	2222.06875	26.85	59,662.55		4.36%			
Citigroup Inc	C	1882.16004	68.43	128,796.21		3.27%		23.17%	
American International Group Inc	AIG	583.77311	81.22	47,414.05	0.13%	2.22%	0.00%	14.77%	0.02%
Altria Group Inc	MO	1686.34139	58.26	98,246.25	0.27%	7.00%	0.02%	4.37%	0.01%
HCA Healthcare Inc	HCA	246.2033	327.92	80,734.99	0.22%	0.88%	0.00%	9.24%	0.02%
International Paper Co	IP	527.87574	47.35	24,994.92		3.91%		54.45%	
Hewlett Packard Enterprise Co	HPE	1313.57824	16.24	21,332.51	0.06%	3.20%	0.00%	4.02%	0.00%
Abbott Laboratories	ABT	1734.32341	128.85	223,467.57	0.61%	1.83%	0.01%	9.85%	0.06%
Aflac Inc	AFL	545.8146	107.94	58,915.23	0.16%	2.15%	0.00%	4.59%	0.01%
Air Products and Chemicals Inc	APD	222.47567	267.11	59,425.48	0.16%	2.68%	0.00%	4.61%	0.01%
Super Micro Computer Inc	SMCI	596.75183	36.47	21,763.54					
Royal Caribbean Cruises Ltd	RCL	271.50933	211.97	57,551.83		1.42%		21.82%	
Hess Corp	HES	309.30974	132.34	40,934.05		1.51%			
Lennox International Inc	LII	35.48483	527.31	18,711.51		0.99%			
Archer-Daniels-Midland Co	ADM	480.15568	48.25	23,167.51	0.06%	4.23%	0.00%	4.44%	0.00%
Automatic Data Processing Inc	ADP	406.87089	291.76	118,708.65	0.32%	2.11%	0.01%	9.70%	0.03%
Verisk Analytics Inc	VRSK	139.94462	286.05	40,031.16	0.11%	0.63%	0.00%	10.35%	0.01%
AutoZone Inc	AZO	16.72866	3609.33	60,379.25	0.16%			8.70%	0.01%
Linde PLC	LIN	472.91162	448.4	212,053.57	0.58%	1.34%	0.01%	6.94%	0.04%
Avery Dennison Corp	AVY	78.966	170.75	13,483.44	0.04%	2.20%	0.00%	6.53%	0.00%
Enphase Energy Inc	ENPH	131.20702	46.83	6,144.42				42.49%	
MSCI Inc	MSCI	77.60163	535.36	41,544.81	0.11%	1.34%	0.00%	9.73%	0.01%
Ball Corp	BALL	282.37887	50.56	14,277.08	0.04%	1.58%	0.00%	10.58%	0.00%
Axon Enterprise Inc	AXON	77.84815	603.78	47,003.16					
Dayforce Inc	DAY	158.26236	57.81	9,149.15					
Carrier Global Corp	CARR	863.98757	60.06	51,891.09	0.14%	1.50%	0.00%	13.47%	0.02%
Bank of New York Mellon Corp/The	BK	717.97392	78.65	56,468.65	0.15%	2.39%	0.00%	13.11%	0.02%
Otis Worldwide Corp	OTIS	394.67659	92.93	36,677.30		1.81%			
Baxter International Inc	BAX	512.92407	30.22	15,500.57	0.04%	2.25%	0.00%	13.59%	0.01%
Becton Dickinson & Co	BDX	287.13542	205.08	58,885.73	0.16%	2.03%	0.00%	8.66%	0.01%
Berkshire Hathaway Inc	BRK/B	1339.90564	530.96	711,436.30					
Best Buy Co Inc	BBY	211.36966	67.71	14,311.84	0.04%	5.61%	0.00%	4.17%	0.00%
Boston Scientific Corp	BSX	1479.0702	101.9	150,717.25	0.41%			12.56%	0.05%
Bristol-Myers Squibb Co	BMY	2035.08081	47.9	97,480.37		5.18%		80.00%	
Brown-Forman Corp	BF/B	303.53996	33.96	10,308.22		2.67%		-2.71%	
Coterra Energy Inc	CTRA	764.09613	25.37	19,385.12		3.47%		29.09%	
Hilton Worldwide Holdings Inc	HLT	239.61402	219.62	52,624.03	0.14%	0.27%	0.00%	12.38%	0.02%
Carnival Corp	CCL	1166.60698	18.6	21,698.89				22.81%	
Builders FirstSource Inc	BLDR	113.74282	121.35	13,802.69	0.04%			1.84%	0.00%
UDR Inc	UDR	331.13336	41.3	13,675.81	0.04%	4.16%	0.00%	1.20%	0.00%
Clorox Co/The	CLX	123.18987	138.27	17,033.46	0.05%	3.53%	0.00%	6.13%	0.00%
Paycom Software Inc	PAYC	57.85232	227.6	13,167.19	0.04%	0.66%	0.00%	9.16%	0.00%
CMS Energy Corp	CMS	299.12375	72.18	21,590.75	0.06%	3.01%	0.00%	7.60%	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.
Colgate-Palmolive Co	CL	810.42012	93.91	76,106.55	0.21%	2.21%	0.00%	4.43%	0.01%
EPAM Systems Inc	EPAM	57.27017	159.12	9,112.83	0.02%			8.81%	0.00%
Conagra Brands Inc	CAG	477.36247	24.45	11,671.51		5.73%		-3.22%	
Airbnb Inc	ABNB	440.00213	122.51	53,904.66	0.15%			9.86%	0.01%
Consolidated Edison Inc	ED	360.20027	110.45	39,784.12	0.11%	3.08%	0.00%	4.89%	0.01%
Corning Inc	GLW	856.77702	44.18	37,852.41	0.10%	2.54%	0.00%	17.67%	0.02%
GoDaddy Inc	GDDY	142.43549	183.4	26,122.67					
Cummins Inc	CMI	137.74258	293.26	40,394.39	0.11%	2.48%	0.00%	8.11%	0.01%
Caesars Entertainment Inc	CZR	208.86195	28.44	5,940.03				58.74%	
Danaher Corp	DHR	715.66959	197.14	141,087.10	0.38%	0.65%	0.00%	8.67%	0.03%
Target Corp	TGT	455.57646	96.58	43,999.57		4.64%			
Williams-Sonoma Inc	WSM	123.5095	151.19	18,673.40	0.05%	1.75%	0.00%	4.50%	0.00%
Deere & Co	DE	271.41393	459.3	124,660.42		1.41%			
Dominion Energy Inc	D	852.21519	52.95	45,124.79		5.04%		23.30%	
Dover Corp	DOV	137.10437	169.01	23,172.01	0.06%	1.22%	0.00%	10.05%	0.01%
Alliant Energy Corp	LNT	256.87321	60.74	15,602.48	0.04%	3.34%	0.00%	6.09%	0.00%
Steel Dynamics Inc	STLD	149.89679	127.34	19,087.86		1.57%			
Duke Energy Corp	DUK	777.02168	119.85	93,126.05	0.25%	3.49%	0.01%	8.00%	0.02%
Regency Centers Corp	REG	181.52587	71.42	12,964.58	0.04%	3.95%	0.00%	4.52%	0.00%
Eaton Corp PLC	ETN	391.76938	288.82	113,150.83	0.31%	1.44%	0.00%	12.42%	0.04%
Ecolab Inc	ECL	283.63255	238.14	67,544.26	0.18%	1.09%	0.00%	13.24%	0.02%
Revvity Inc	RVTY	120.14729	94.29	11,328.69	0.03%	0.30%	0.00%	8.52%	0.00%
Dell Technologies Inc	DELL	358.71036	94.89	34,038.03	0.09%	2.21%	0.00%	13.18%	0.01%
Emerson Electric Co	EMR	563.9	105.28	59,367.39	0.16%	2.00%	0.00%	9.10%	0.01%
EOG Resources Inc	EOG	551.5444	113.07	62,363.13		3.61%		-7.26%	
Aon PLC	AON	216.00111	335.85	72,543.97	0.20%	0.89%	0.00%	9.99%	0.02%
Entergy Corp	ETR	446.34088	84.61	37,764.90	0.10%	2.84%	0.00%	5.80%	0.01%
Equifax Inc	EFX	124.19904	256.48	31,854.57	0.09%	0.78%	0.00%	14.23%	0.01%
EQT Corp	EQT	598.626	50.24	30,074.97		1.25%		46.31%	
IQVIA Holdings Inc	IQV	176.31504	150.28	26,496.62	0.07%			9.22%	0.01%
Gartner Inc	IT	77.0592	416.09	32,063.56					
FedEx Corp	FDX	239.59892	211.56	50,689.55	0.14%	2.61%	0.00%	11.06%	0.02%
Brown & Brown Inc	BRO	286.6276	114.44	32,801.66	0.09%	0.52%	0.00%	8.98%	0.01%
Ford Motor Co	F	3905.6954	10.04	39,213.18	0.11%	5.98%	0.01%	0.18%	0.00%
NextEra Energy Inc	NEE	2058.63111	66.09	136,054.93	0.37%	3.43%	0.01%	7.40%	0.03%
Franklin Resources Inc	BEN	525.39798	18.72	9,835.45		6.84%		-3.45%	
Garmin Ltd	GRMN	192.64121	198.96	38,327.90	0.10%	1.81%	0.00%	11.16%	0.01%
Freeport-McMoRan Inc	FCX	1437.07301	37.35	53,674.68	0.15%	1.61%	0.00%	16.50%	0.02%
Expand Energy Corp	EXE	237.97408	105.3	25,058.67		2.18%		62.31%	
Dexcom Inc	DXCM	392.1075	71.66	28,098.42				21.20%	
General Dynamics Corp	GD	268.39616	271.97	72,995.70	0.20%	2.21%	0.00%	13.82%	0.03%
General Mills Inc	GIS	547.60053	56.14	30,742.29		4.28%		-2.42%	
Genuine Parts Co	GPC	138.78964	116.64	16,188.42		3.53%			
Atmos Energy Corp	ATO	158.7282	158.14	25,101.28	0.07%	2.20%	0.00%	7.14%	0.00%
WW Grainger Inc	GWW	48.17143	1013.87	48,839.57	0.13%	0.89%	0.00%	5.89%	0.01%
Halliburton Co	HAL	859.71502	20.85	17,925.06		3.26%		-2.39%	
L3Harris Technologies Inc	LHX	186.94564	216.08	40,395.21	0.11%	2.22%	0.00%	11.51%	0.01%
Healthpeak Properties Inc	DOC	698.59612	17.83	12,455.97	0.03%	6.84%	0.00%	4.74%	0.00%
Insulet Corp	PODD	70.2261	260.71	18,308.65				25.86%	
Fortive Corp	FTV	339.87626	68.92	23,424.27	0.06%	0.46%	0.00%	6.28%	0.00%
Hershey Co/The	HSY	147.94946	163.28	24,157.19		3.36%		-9.26%	
Synchrony Financial	SYF	380.65071	51.42	19,573.06	0.05%	2.33%	0.00%	17.55%	0.01%
Hormel Foods Corp	HRL	549.9125	29.7	16,332.40	0.04%	3.91%	0.00%	5.97%	0.00%
Arthur J Gallagher & Co	AJG	255.7348	322.3	82,423.33		0.81%			
Mondelez International Inc	MDLZ	1295.53504	65.59	84,974.14		2.87%			
CenterPoint Energy Inc	CNP	652.72675	38.19	24,927.63	0.07%	2.30%	0.00%	8.05%	0.01%
Humana Inc	HUM	120.69263	264.4	31,911.13	0.09%	1.34%	0.00%	10.76%	0.01%
Willis Towers Watson PLC	WTW	99.14979	302.19	29,962.08	0.08%	1.22%	0.00%	7.08%	0.01%
Illinois Tool Works Inc	ITW	293.36598	239.5	70,261.15	0.19%	2.51%	0.00%	2.25%	0.00%
CDW Corp/DE	CDW	131.76671	157.95	20,812.55	0.06%	1.58%	0.00%	6.38%	0.00%
Trane Technologies PLC	TT	223.17593	347.97	77,658.53	0.21%	1.08%	0.00%	10.09%	0.02%
Interpublic Group of Cos Inc/The	IPG	369.73471	24.56	9,080.68		5.37%			
International Flavors & Fragrances Inc	IFF	255.73501	76.24	19,497.24	0.05%	2.10%	0.00%	4.29%	0.00%
Generac Holdings Inc	GNRC	59.61403	112.89	6,729.83	0.02%			17.92%	0.00%
NXP Semiconductors NV	NXPI	253.62012	193.55	49,088.17	0.13%	2.10%	0.00%	4.83%	0.01%
Kellanova	K	345.21592	82.62	28,521.74	0.08%	2.76%	0.00%	3.02%	0.00%
Broadridge Financial Solutions Inc	BR	117.01869	237.72	27,817.68		1.48%			
Kimberly-Clark Corp	KMB	331.81604	131.61	43,670.31	0.12%	3.83%	0.00%	3.40%	0.00%
Kimco Realty Corp	KIM	679.49863	20.35	13,827.80	0.04%	4.91%	0.00%	3.80%	0.00%
Oracle Corp	ORCL	2804.234	138.49	388,358.37	1.06%	1.44%	0.02%	8.44%	0.09%
Kroger Co/The	KR	660.89348	70	46,262.54	0.13%	1.83%	0.00%	6.11%	0.01%
Lennar Corp	LEN	232.18447	107.63	24,990.01		1.86%		-4.18%	
Eli Lilly & Co	LLY	947.98915	884.54	838,534.32	2.28%	0.68%	0.02%	19.30%	0.44%
Charter Communications Inc	CHTR	140.36423	373.65	52,447.09				20.49%	
Loews Corp	L	210.34191	85.27	17,935.85		0.29%			
Lowe's Cos Inc	LOW	559.70581	220.91	123,644.61	0.34%	2.17%	0.01%	6.22%	0.02%
Hubbell Inc	HUBB	53.57336	359.84	19,277.84		1.47%			
IDEX Corp	IEX	75.54411	173	13,069.13		1.64%			
Marsh & McLennan Cos Inc	MMC	492.72776	219.24	108,025.63	0.29%	1.49%	0.00%	8.52%	0.03%
Masco Corp	MAS	210.94202	60.42	12,745.12	0.03%	2.05%	0.00%	7.38%	0.00%
S&P Global Inc	SPGI	313.84007	480	150,643.23	0.41%	0.80%	0.00%	14.70%	0.06%
Medtronic PLC	MDT	1282.5435	84.16	107,938.86	0.29%	3.37%	0.01%	5.30%	0.02%
Viatris Inc	VTRS	1193.68875	8.13	9,704.69		5.90%		-3.79%	
CVS Health Corp	CVS	1262.38383	65.32	82,458.91	0.22%	4.07%	0.01%	14.85%	0.03%
DuPont de Nemours Inc	DD	418.4985	65.69	27,491.17	0.07%	2.50%	0.00%	6.89%	0.01%
Micron Technology Inc	MU	1117.57152	79.78	89,159.86		0.58%			
Motorola Solutions Inc	MSI	166.96355	430.22	71,831.06	0.20%	1.01%	0.00%	7.41%	0.01%
Cboe Global Markets Inc	CBOE	104.71247	213.59	22,365.54	0.06%	1.18%	0.00%	10.54%	0.01%
Newmont Corp	NEM	1112.99693	53.94	60,035.05	0.16%	1.85%	0.00%	14.18%	0.02%
NIKE Inc	NKE	1178.10274	57.62	67,882.28		2.78%		-6.80%	
NiSource Inc	NI	470.60544	39.45	18,565.38	0.05%	2.84%	0.00%	7.22%	0.00%
Norfolk Southern Corp	NSC	225.4435	221.71	49,983.08	0.14%	2.44%	0.00%	11.89%	0.02%
Principal Financial Group Inc	PFG	224.97172	73.46	16,526.42	0.05%	4.14%	0.00%	12.17%	0.01%
Eversource Energy	ES	367.0819	57.86	21,239.36	0.06%	5.20%	0.00%	4.47%	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.
Northrop Grumman Corp	NOC	143.92818	473.2	68,106.81	0.19%	1.95%	0.00%	4.19%	0.01%
Wells Fargo & Co	WFC	3265.15883	69.73	227,679.53	0.62%	2.29%	0.01%	14.29%	0.09%
Nucor Corp	NUE	230.74613	115.72	26,701.94		1.90%			
Occidental Petroleum Corp	OXY	939.78256	40.36	37,929.62		2.38%			
Omnicom Group Inc	OMC	195.10941	74.92	14,617.60	0.04%	3.74%	0.00%	4.99%	0.00%
ONEOK Inc	OKE	624.62165	86.31	53,911.09		4.77%			
Raymond James Financial Inc	RJF	204.91003	137.37	28,148.49	0.08%	1.46%	0.00%	8.07%	0.01%
PG&E Corp	PCG	2675.4286	17.14	45,856.85		0.58%			
Parker-Hannifin Corp	PH	128.76484	598.02	77,003.95	0.21%	1.20%	0.00%	7.09%	0.01%
Rollins Inc	ROL	484.64646	55.31	26,805.80		1.19%			
PPL Corp	PPL	739.05159	35.93	26,554.12		3.03%			
Aptiv PLC	APTV	229.44637	55.93	12,832.94					
ConocoPhillips	COP	1264.16535	91.72	115,949.25		3.40%			
PulteGroup Inc	PHM	200.42718	101.88	20,419.52		0.86%		-1.13%	
Pinnacle West Capital Corp	PNW	119.21493	93.75	11,176.40		3.82%			
PNC Financial Services Group Inc/The	PNC	395.74958	158.46	62,710.48	0.17%	4.04%	0.01%	7.49%	0.01%
PPG Industries Inc	PPG	226.9749	102.57	23,280.82	0.06%	2.65%	0.00%	5.76%	0.00%
DoorDash Inc	DASH	398.14139	187.76	74,755.03				150.66%	
Progressive Corp/The	PGR	586.23611	265.01	155,358.43	0.42%	0.15%	0.00%	13.88%	0.06%
Veralto Corp	VLTO	248.05176	92.31	22,897.66		0.48%			
Public Service Enterprise Group Inc	PEG	498.56147	81.03	40,398.44	0.11%	3.11%	0.00%	8.56%	0.01%
Cooper Cos Inc/The	COO	199.98118	80.89	16,176.48	0.04%			10.21%	0.00%
Edison International	EIX	385.02353	57.96	22,315.96	0.06%	5.71%	0.00%	9.71%	0.01%
Schlumberger NV	SLB	1360.16165	34.52	46,952.78		3.30%		-0.49%	
Charles Schwab Corp/The	SCHW	1815.91791	79.94	145,164.48	0.40%	1.35%	0.01%	19.69%	0.08%
Sherwin-Williams Co/The	SHW	251.51015	331.62	83,405.80	0.23%	0.95%	0.00%	5.91%	0.01%
West Pharmaceutical Services Inc	WST	71.84536	214.55	15,414.42	0.04%	0.39%	0.00%	6.27%	0.00%
J M Smucker Co/The	SJM	106.41662	115.23	12,262.39	0.03%	3.75%	0.00%	3.28%	0.00%
Snap-on Inc	SNA	52.29102	308.76	16,145.38	0.04%	2.77%	0.00%	3.46%	0.00%
AMETEK Inc	AME	230.74691	166.69	38,463.20	0.10%	0.74%	0.00%	8.18%	0.01%
Uber Technologies Inc	UBER	2091.25811	77.75	162,595.32				-5.22%	
Southern Co/The	SO	1100.19364	90.43	99,490.51	0.27%	3.27%	0.01%	6.42%	0.02%
Truist Financial Corp	TFC	1305.39071	37.67	49,174.07	0.13%	5.52%	0.01%	7.53%	0.01%
Southwest Airlines Co	LUV	569.8658	26.49	15,095.75		2.72%		57.29%	
W R Berkley Corp	WRB	379.31287	70.48	26,733.97	0.07%	0.45%	0.00%	6.85%	0.00%
Stanley Black & Decker Inc	SWK	154.53752	61.58	9,516.42		5.33%			
Public Storage	PSA	175.41747	290.91	51,030.70	0.14%	4.12%	0.01%	3.96%	0.01%
Arista Networks Inc	ANET	1255.62551	77.91	97,825.78	0.27%			14.97%	0.04%
Sysco Corp	SYY	489.22964	70.93	34,701.06		3.05%			
Corteva Inc	CTVA	683.01458	61.47	41,984.91	0.11%	1.11%	0.00%	16.85%	0.02%
Texas Instruments Inc	TXN	908.47208	162.86	147,953.76	0.40%	3.34%	0.01%	11.66%	0.05%
Textron Inc	TXT	180.5388	68.42	12,352.46	0.03%	0.12%	0.00%	10.03%	0.00%
Thermo Fisher Scientific Inc	TMO	377.49229	424.24	160,147.33	0.44%	0.41%	0.00%	8.08%	0.04%
TJX Cos Inc/The	TJX	1117.10049	126.56	141,380.24	0.38%	1.34%	0.01%	8.16%	0.03%
Globe Life Inc	GL	83.24275	122.96	10,235.53		0.88%			
Johnson Controls International plc	JCI	660.13919	81.07	53,517.48	0.15%	1.83%	0.00%	9.92%	0.01%
Ulta Beauty Inc	ULTA	45.14788	383.67	17,321.89	0.05%			3.57%	0.00%
Union Pacific Corp	UNP	597.47561	213.29	127,435.57	0.35%	2.51%	0.01%	9.19%	0.03%
Keysight Technologies Inc	KEYS	172.81051	144.01	24,886.44	0.07%			12.93%	0.01%
UnitedHealth Group Inc	UNH	910.22379	418.64	381,056.09	1.04%	2.01%	0.02%	6.78%	0.07%
Blackstone Inc	BX	729.41593	132.86	96,910.20		2.80%		21.63%	
Ventas Inc	VTR	437.6978	68.16	29,833.48	0.08%	2.82%	0.00%	10.12%	0.01%
Labcorp Holdings Inc	LH	83.66834	228.31	19,102.32	0.05%	1.26%	0.00%	10.11%	0.01%
Vulcan Materials Co	VMC	132.10118	247.04	32,634.28	0.09%	0.79%	0.00%	13.07%	0.01%
Weyerhaeuser Co	WY	725.84891	24.81	18,008.31	0.05%	3.39%	0.00%	1.24%	0.00%
Williams Cos Inc/The	WMB	1220.68675	59.03	72,057.14		3.39%			
Constellation Energy Corp	CEG	315.12094	222.99	70,268.82	0.19%	0.70%	0.00%	12.06%	0.02%
WEC Energy Group Inc	WEC	319.0892	107.73	34,375.48	0.09%	3.31%	0.00%	7.53%	0.01%
Adobe Inc	ADBE	426.2	367.72	156,722.26	0.43%			13.49%	0.06%
Vistra Corp	VST	340.15707	126.64	43,077.49	0.12%	0.71%	0.00%	3.01%	0.00%
AES Corp/The	AES	711.90055	10.05	7,154.60	0.02%	7.00%	0.00%	3.46%	0.00%
Expeditors International of Washington Inc	EXPD	137.7567	108.58	14,957.62	0.04%	1.42%	0.00%	3.54%	0.00%
Amgen Inc	AMGN	537.65062	280.84	150,993.80	0.41%	3.39%	0.01%	4.92%	0.02%
Apple Inc	AAPL	15022.073	209.28	3,143,819.44	8.56%	0.50%	0.04%	12.77%	1.09%
Autodesk Inc	ADSK	213	269.93	57,495.09	0.16%			14.58%	0.02%
Cintas Corp	CTAS	403.78696	208.4	84,149.20	0.23%	0.75%	0.00%	14.37%	0.03%
Comcast Corp	CMCSA	3724.25955	33.9	126,252.40	0.34%	3.89%	0.01%	3.20%	0.01%
Molson Coors Beverage Co	TAP	190.29203	56.8	10,808.59	0.03%	3.31%	0.00%	6.21%	0.00%
KLA Corp	KLAC	132.88675	694.61	92,304.47	0.25%	1.09%	0.00%	15.89%	0.04%
Marriott International Inc/MD	MAR	275.37279	236.2	65,043.05	0.18%	1.13%	0.00%	10.45%	0.02%
Fiserv Inc	FI	554.43382	177.53	98,428.64	0.27%			15.52%	0.04%
McCormick & Co Inc/MD	MKC	252.68173	74.54	18,834.90	0.05%	2.41%	0.00%	6.37%	0.00%
PACCAR Inc	PCAR	524.93477	91.89	48,236.26		1.44%			
Costco Wholesale Corp	COST	443.68336	977.16	433,549.63	1.18%	0.53%	0.01%	8.86%	0.10%
Stryker Corp	SYK	381.68884	365.06	139,339.33	0.38%	0.92%	0.00%	10.33%	0.04%
Tyson Foods Inc	TSN	286.18537	60.62	17,348.56	0.05%	3.30%	0.00%	19.57%	0.01%
Lamb Weston Holdings Inc	LW	141.11562	51.94	7,329.55		2.85%			
Applied Materials Inc	AMAT	812.44085	151.55	123,125.41	0.34%	1.21%	0.00%	9.44%	0.03%
Cardinal Health Inc	CAH	241.56799	137.56	33,230.09	0.09%	1.49%	0.00%	9.69%	0.01%
Cincinnati Financial Corp	CINF	156.56473	133.69	20,931.14	0.06%	2.60%	0.00%	2.85%	0.00%
Paramount Global	PARA	630.00763	11.73	7,389.99		1.71%			
DR Horton Inc	DHI	307.18129	124.56	38,262.50	0.10%	1.28%	0.00%	1.58%	0.00%
Electronic Arts Inc	EA	260.61759	146.6	38,206.54	0.10%	0.52%	0.00%	10.27%	0.01%
Erie Indemnity Co	ERIE	46.18907	361.85	16,713.51		1.51%			
Fair Isaac Corp	FICO	24.41814	1952.31	47,671.78				27.55%	
Fastenal Co	FAST	573.62064	80.73	46,308.39	0.13%	1.09%	0.00%	10.52%	0.01%
M&T Bank Corp	MTB	164.29035	167.39	27,500.56	0.07%	3.23%	0.00%	11.79%	0.01%
Xcel Energy Inc	XEL	576.76061	69	39,796.48		3.30%			
Fifth Third Bancorp	FITB	668.09892	35.28	23,570.53		4.20%			
Gilead Sciences Inc	GILD	1245.16279	103.17	128,463.45		3.06%		28.62%	
Hasbro Inc	HAS	139.8932	60.99	8,532.09	0.02%	4.59%	0.00%	8.59%	0.00%
Huntington Bancshares Inc/OH	HBAN	1460.75396	14.4	21,034.86	0.06%	4.31%	0.00%	12.92%	0.01%
Welltower Inc	WELL	651.53639	146.96	95,749.79	0.26%	1.82%	0.00%	16.89%	0.04%
Biogen Inc	BIIB	146.37494	118.84	17,395.20	0.05%			1.22%	0.00%

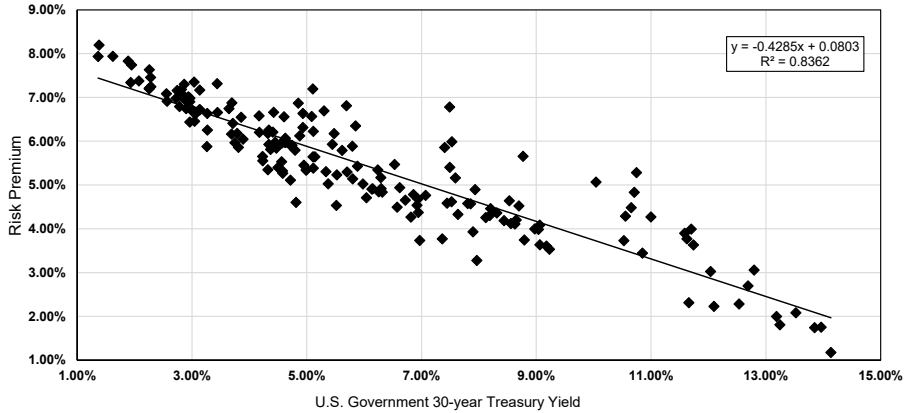
Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Northern Trust Corp	NTRS	194.97161	91.59	17,857.45	0.05%	3.28%	0.00%	9.64%	0.00%
Packaging Corp of America	PKG	89.92812	184.82	16,620.52	0.05%	2.71%	0.00%	7.40%	0.00%
Paychex Inc	PAYX	360.19067	143.21	51,582.91	0.14%	3.02%	0.00%	6.24%	0.01%
QUALCOMM Inc	QCOM	1106	148.56	164,307.36	0.45%	2.40%	0.01%	15.26%	0.07%
Ross Stores Inc	ROST	328.83421	139.71	45,941.43	0.13%	1.16%	0.00%	5.78%	0.01%
IDEXX Laboratories Inc	IDXX	81.03904	437.44	35,449.72	0.10%			11.51%	0.01%
Starbucks Corp	SBUX	1135.9	83.81	95,199.78	0.26%	2.91%	0.01%	8.60%	0.02%
KeyCorp	KEY	1095.71722	14.72	16,128.96	0.04%	5.57%	0.00%	19.35%	0.01%
Fox Corp	FOXA	217.84683	49.35	10,750.74	0.03%	1.09%	0.00%	10.12%	0.00%
Fox Corp	FOX	235.58103	45.79	10,787.26	0.03%	1.18%	0.00%	10.12%	0.00%
State Street Corp	STT	288.59098	87.38	25,217.08	0.07%	3.48%	0.00%	10.63%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	443.21938	17.23	7,636.67	0.02%			13.70%	0.00%
US Bancorp	USB	1558.01053	39.92	62,195.78	0.17%	5.01%	0.01%	10.38%	0.02%
A O Smith Corp	AOS	117.65899	64.99	7,646.66		2.09%			
Gen Digital Inc	GEN	616.30137	25.26	15,567.77	0.04%	1.98%	0.00%	10.56%	0.00%
T Rowe Price Group Inc	TROW	222.24239	88.44	19,655.12		5.74%		-4.02%	
Waste Management Inc	WM	402.33242	228.31	91,856.51	0.25%	1.45%	0.00%	10.48%	0.03%
Constellation Brands Inc	STZ	177.99303	185.35	32,991.01	0.09%	2.20%	0.00%	1.36%	0.00%
Invesco Ltd	IVZ	447.41359	13.93	6,232.47	0.02%	6.03%	0.00%	3.37%	0.00%
Intuit Inc	INTU	279.562	624.12	174,480.24	0.48%	0.67%	0.00%	15.57%	0.07%
Morgan Stanley	MS	1608.50778	116.01	186,602.99	0.51%	3.19%	0.02%	10.29%	0.05%
Microchip Technology Inc	MCHP	537.81897	46.89	25,218.33		3.88%		30.33%	
Crowdstrike Holdings Inc	CRWD	247.87342	424.88	105,316.46				24.67%	
Chubb Ltd	CB	400.6851	279.11	111,835.22	0.30%	1.39%	0.00%	4.24%	0.01%
Hologic Inc	HOLX	225.72311	58.02	13,096.45	0.04%			6.51%	0.00%
Citizens Financial Group Inc	CFG	437.13389	37.06	16,200.18		4.53%		23.45%	
Jabil Inc	JBL	107.34535	146.92	15,771.18	0.04%	0.22%	0.00%	12.83%	0.01%
O'Reilly Automotive Inc	ORLY	57.24051	1347	77,102.97	0.21%			9.80%	0.02%
Allstate Corp/The	ALL	265.13908	192.91	51,147.98	0.14%	2.07%	0.00%	14.13%	0.02%
Equity Residential	EQR	379.84068	68.53	26,030.48	0.07%	4.04%	0.00%	3.64%	0.00%
Keurig Dr Pepper Inc	KDP	1358.17807	34.4	46,721.33	0.13%	2.67%	0.00%	6.20%	0.01%
Host Hotels & Resorts Inc	HST	698.67137	13.88	9,697.56		5.76%		-1.61%	
Incyte Corp	INCY	193.52435	59.16	11,448.90				25.00%	
Simon Property Group Inc	SPG	326.24342	156.66	51,109.29	0.14%	5.36%	0.01%	1.22%	0.00%
Eastman Chemical Co	EMN	115.46015	75.84	8,756.50	0.02%	4.38%	0.00%	4.52%	0.00%
AvalonBay Communities Inc	AVB	142.36862	205.76	29,293.77	0.08%	3.40%	0.00%	5.91%	0.00%
Prudential Financial Inc	PRU	354.42709	102.9	36,470.55	0.10%	5.25%	0.01%	7.66%	0.01%
United Parcel Service Inc	UPS	733.68671	97.91	71,835.27	0.20%	6.70%	0.01%	7.16%	0.01%
Walgreens Boots Alliance Inc	WBA	864.7379	11.01	9,520.76				-21.75%	
STERIS PLC	STE	98.25079	225	22,106.43		1.01%			
McKesson Corp	MCK	125.32638	695	87,101.83	0.24%	0.41%	0.00%	10.84%	0.03%
Lockheed Martin Corp	LMT	234.29595	477.64	111,909.12	0.30%	2.76%	0.01%	11.65%	0.04%
Cencora Inc	COR	193.71259	285.9	55,382.43	0.15%	0.77%	0.00%	9.97%	0.02%
Capital One Financial Corp	COF	381.47946	182.73	69,707.74		1.31%		22.43%	
The Campbell's Company	CPB	298.18187	36.29	10,821.02	0.03%	4.30%	0.00%	1.17%	0.00%
Waters Corp	WAT	59.49579	337.89	20,103.03	0.05%			8.83%	0.00%
Nordson Corp	NDSN	56.91174	188.22	10,711.93		1.66%			
Dollar Tree Inc	DLTR	215.08301	80.57	17,329.24	0.05%			8.42%	0.00%
Darden Restaurants Inc	DRI	117.02625	199.1	23,299.93	0.06%	2.81%	0.00%	9.10%	0.01%
Evergy Inc	EVRG	229.74594	67.88	15,595.15	0.04%	3.93%	0.00%	5.71%	0.00%
Match Group Inc	MTCH	246.67838	30.07	7,417.62	0.02%	2.53%	0.00%	11.57%	0.00%
NVR Inc	NVR	2.969	7071.42	20,995.05	0.06%			4.50%	0.00%
NetApp Inc	NTAP	203.41152	88.45	17,991.75	0.05%	2.35%	0.00%	4.98%	0.00%
Old Dominion Freight Line Inc	ODFL	212.14703	146.74	31,130.46	0.08%	0.76%	0.00%	7.72%	0.01%
DaVita Inc	DVA	76.86333	139.56	10,727.05	0.03%			10.59%	0.00%
Hartford Insurance Group Inc/The	HIG	284.10299	118.76	33,740.07	0.09%	1.75%	0.00%	9.44%	0.01%
Iron Mountain Inc	IRM	294.96818	87.72	25,874.61		3.58%			
Estee Lauder Cos Inc/The	EL	234.17342	59.39	13,907.56	0.04%	2.36%	0.00%	5.02%	0.00%
Cadence Design Systems Inc	CDNS	274.3136	289.63	79,449.45	0.22%			13.72%	0.03%
Tyler Technologies Inc	TYL	43.12355	524.64	22,624.34					
Universal Health Services Inc	UHS	57.95194	171.68	9,949.19	0.03%	0.47%	0.00%	11.12%	0.00%
Skyworks Solutions Inc	SWKS	153.57483	61.52	9,447.92		4.55%		-9.34%	
Quest Diagnostics Inc	DGX	111.63547	173.76	19,397.78	0.05%	1.84%	0.00%	8.44%	0.00%
Rockwell Automation Inc	ROK	113.07295	248.38	28,085.06	0.08%	2.11%	0.00%	10.92%	0.01%
Kraft Heinz Co/The	KHC	1193.39837	29.49	35,193.32		5.43%		-4.68%	
American Tower Corp	AMT	468.11784	210.82	98,688.60		3.23%		25.83%	
Regeneron Pharmaceuticals Inc	REGN	106.95152	602.64	64,453.26	0.18%	0.58%	0.00%	7.64%	0.01%
Amazon.com Inc	AMZN	10612.364	188.99	2,005,630.67	5.46%			13.43%	0.73%
Jack Henry & Associates Inc	JKHY	72.89767	170.93	12,460.40	0.03%	1.36%	0.00%	10.10%	0.00%
Ralph Lauren Corp	RL	39.88294	219.96	8,772.65	0.02%	1.66%	0.00%	9.62%	0.00%
BXP Inc	BXP	158.2096	65.85	10,418.10	0.03%	5.95%	0.00%	1.33%	0.00%
Amphenol Corp	APH	1211.78331	75.85	91,913.76	0.25%	0.87%	0.00%	18.81%	0.05%
Howmet Aerospace Inc	HWM	404.46374	135.76	54,910.00	0.15%	0.29%	0.00%	14.14%	0.02%
Valero Energy Corp	VLO	313.20612	113.87	35,664.78		3.97%			
Synopsys Inc	SNPS	154.62008	446.62	69,056.42	0.19%			13.88%	0.03%
CH Robinson Worldwide Inc	CHRW	118.22702	89.75	10,610.88	0.03%	2.76%	0.00%	15.23%	0.00%
Accenture PLC	ACN	626.02583	293.39	183,669.72	0.50%	2.02%	0.01%	7.12%	0.04%
TransDigm Group Inc	TDG	56.08459	1378.13	77,291.86	0.21%			13.51%	0.03%
Yum! Brands Inc	YUM	278.5	147.3	41,023.05	0.11%	1.93%	0.00%	10.40%	0.01%
Prologis Inc	PLD	926.175	102.24	94,692.13	0.26%	3.95%	0.01%	5.83%	0.02%
FirstEnergy Corp	FE	577.12618	42.34	24,435.52	0.07%	4.20%	0.00%	0.83%	0.00%
VeriSign Inc	VRSN	93.9	272.79	25,614.98		1.13%			
Quanta Services Inc	PWR	148.26363	287.34	42,602.07	0.12%	0.14%	0.00%	13.51%	0.02%
Henry Schein Inc	HSIC	122.51195	65.17	7,984.10	0.02%			7.63%	0.00%
Ameren Corp	AEE	270.15767	98.28	26,551.10		2.89%			
ANSYS Inc	ANSS	87.65178	320.68	28,108.17	0.08%			11.10%	0.01%
FactSet Research Systems Inc	FDS	37.94706	424.47	16,107.39		1.04%			
NVIDIA Corp	NVDA	24400	111.01	2,708,644.00		0.04%		34.22%	
Cognizant Technology Solutions Corp	CTSH	492.9393	72.17	35,575.43	0.10%	1.72%	0.00%	7.13%	0.01%
Intuitive Surgical Inc	ISRG	358.41826	514.59	184,438.45	0.50%			13.49%	0.07%
Take-Two Interactive Software Inc	TTWO	176.49571	225.38	39,778.60				58.00%	
Republic Services Inc	RSG	312.49701	243.56	76,111.77	0.21%	0.95%	0.00%	9.36%	0.02%
eBay Inc	EBAY	466	67.83	31,608.78	0.09%	1.71%	0.00%	8.60%	0.01%
Goldman Sachs Group Inc/The	GS	310.79039	544.86	169,337.25	0.46%	2.20%	0.01%	13.24%	0.06%

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.
SBA Communications Corp	SBAC	108.02812	222.09	23,991.97	0.07%	2.00%	0.00%	10.84%	0.01%
Sempra	SRE	651.91337	74.68	48,684.89	0.13%	3.45%	0.00%	6.51%	0.01%
Moody's Corp	MCO	179.9	438.62	78,907.74	0.21%	0.86%	0.00%	12.82%	0.03%
ON Semiconductor Corp	ON	422.04943	39.63	16,725.82					
Booking Holdings Inc	BKNG	32.69914	4838.44	158,212.83	0.43%	0.79%	0.00%	16.03%	0.07%
F5 Inc	FFIV	57.65226	270.03	15,567.84	0.04%			6.89%	0.00%
Akamai Technologies Inc	AKAM	146.11477	79.79	11,658.50				-0.21%	
Charles River Laboratories International Inc	CRL	49.11571	114.66	5,631.61	0.02%			3.37%	0.00%
MarketAxess Holdings Inc	MKTX	37.20139	219	8,147.10		1.39%		-0.46%	
Devon Energy Corp	DVN	643.32922	31.35	20,168.37	0.05%	3.06%	0.00%	3.42%	0.00%
Bio-Techne Corp	TECH	158.08768	50.24	7,942.33		0.64%			
Alphabet Inc	GOOGL	5820	161.96	942,607.20	2.57%	0.52%	0.01%	12.96%	0.33%
Allegion plc	ALLE	86.04929	136.49	11,744.87	0.03%	1.49%	0.00%	4.57%	0.00%
Netflix Inc	NFLX	425.57127	1101.53	468,779.52				25.26%	
Agilent Technologies Inc	A	285.10272	106.28	30,300.72	0.08%	0.93%	0.00%	5.90%	0.00%
Warner Bros Discovery Inc	WBD	2473.83561	8.59	21,250.25				41.31%	
Trimble Inc	TRMB	238.58349	61.71	14,722.99					
Elevance Health Inc	ELV	225.9346	421.68	95,272.10	0.26%	1.62%	0.00%	9.30%	0.02%
CME Group Inc	CME	360.37957	266.3	95,969.08	0.26%	1.88%	0.00%	7.82%	0.02%
Juniper Networks Inc	JNPR	334.27709	35.6	11,900.26	0.03%	2.47%	0.00%	12.36%	0.00%
DTE Energy Co	DTE	207.51775	134.76	27,965.09	0.08%	3.24%	0.00%	5.90%	0.00%
Nasdaq Inc	NDAQ	574.12162	75.36	43,265.81	0.12%	1.43%	0.00%	12.82%	0.02%
Philip Morris International Inc	PM	1556.51718	170.24	264,981.48	0.72%	3.17%	0.02%	11.22%	0.08%
Ingersoll Rand Inc	IR	403.08325	74.98	30,223.18		0.11%			
Salesforce Inc	CRM	959.47357	267.85	256,995.00	0.70%	0.62%	0.00%	11.67%	0.08%
Roper Technologies Inc	ROP	107.38521	557.7	59,888.73		0.59%			
Huntington Ingalls Industries Inc	HII	39.23557	226.05	8,869.20	0.02%	2.39%	0.00%	13.94%	0.00%
MetLife Inc	MET	681.22803	75.19	51,221.54	0.14%	3.02%	0.00%	13.76%	0.02%
Tapestry Inc	TPR	207.01547	68.88	14,259.23	0.04%	2.03%	0.00%	9.81%	0.00%
CSX Corp	CSX	1878.54587	27.84	52,298.72	0.14%	1.87%	0.00%	7.13%	0.01%
Edwards Lifesciences Corp	EW	587.8649	76.04	44,701.25	0.12%			7.04%	0.01%
Ameriprise Financial Inc	AMP	95.81396	465.94	44,643.56	0.12%	1.37%	0.00%	7.28%	0.01%
Zebra Technologies Corp	ZBRA	51.14332	246.24	12,593.53					
Zimmer Biomet Holdings Inc	ZBH	197.84133	101.51	20,082.87	0.05%	0.95%	0.00%	2.16%	0.00%
Camden Property Trust	CPT	108.79919	114	12,403.11	0.03%	3.68%	0.00%	1.91%	0.00%
CBRE Group Inc	CBRE	298.10485	120.73	35,990.20					
Mastercard Inc	MA	902.48719	533.48	481,458.87	1.31%	0.57%	0.01%	13.19%	0.17%
CarMax Inc	KMX	152.68423	65.03	9,929.06					
Intercontinental Exchange Inc	ICE	574.49802	163.23	93,775.31	0.26%	1.18%	0.00%	16.39%	0.04%
Fidelity National Information Services Inc	FIS	529.69159	79.26	41,983.36	0.11%	2.02%	0.00%	9.37%	0.01%
Smurfit WestRock PLC	SW	521.97915	42.23	22,043.18		4.08%			
Chipotle Mexican Grill Inc	CMG	1347.364	51.78	69,766.51	0.19%			16.26%	0.03%
Wynn Resorts Ltd	WYNN	106.16733	82.11	8,717.40	0.02%	1.22%	0.00%	7.84%	0.00%
Live Nation Entertainment Inc	LYV	234.08951	132.76	31,077.72	0.08%			3.98%	0.00%
Assurant Inc	AIZ	50.86794	190.83	9,707.13		1.68%			
NRG Energy Inc	NRG	203.66697	108.33	22,063.24	0.06%	1.62%	0.00%	3.60%	0.00%
Monster Beverage Corp	MNST	973.1589	58.67	57,095.23	0.16%			12.95%	0.02%
Regions Financial Corp	RF	905.46507	20.28	18,362.83	0.05%	4.93%	0.00%	6.18%	0.00%
Baker Hughes Co	BKR	990.74998	36.45	36,112.84	0.10%	2.52%	0.00%	8.81%	0.01%
Mosaic Co/The	MOS	317.22973	29.13	9,240.90		3.02%			
Expedia Group Inc	EXPE	122.0414	160.11	19,540.05	0.05%	1.00%	0.00%	16.27%	0.01%
CF Industries Holdings Inc	CF	166.4672	78.47	13,062.68		2.55%		-4.82%	
APA Corp	APA	361.66386	16.35	5,913.20	0.02%	6.12%	0.00%	1.05%	0.00%
Leidos Holdings Inc	LDOS	128.21387	145.71	18,682.04	0.05%	1.10%	0.00%	7.40%	0.00%
Alphabet Inc	GOOG	5459	163.85	894,457.15	2.44%	0.51%	0.01%	12.96%	0.32%
TKO Group Holdings Inc	TKO	81.55382	157.1	12,812.11		0.97%			
First Solar Inc	FSLR	107.24042	141.86	15,213.13				35.90%	
Discover Financial Services	DFS	251.60413	184.86	46,511.54	0.13%			1.61%	0.00%
Visa Inc	V	1723.36235	335.17	577,619.36	1.57%	0.70%	0.01%	13.00%	0.20%
Mid-America Apartment Communities Inc	MAA	116.90086	159.38	18,631.66	0.05%	3.80%	0.00%	1.92%	0.00%
Xylem Inc/NY	XYL	243.34947	116.1	28,252.87		1.38%			
Marathon Petroleum Corp	MPC	311.53136	137.44	42,816.87	0.12%	2.65%	0.00%	8.59%	0.01%
Tractor Supply Co	TSCO	531.61539	49.92	26,538.24	0.07%	1.84%	0.00%	8.70%	0.01%
Advanced Micro Devices Inc	AMD	1624.63337	96.645	157,012.69				27.19%	
ResMed Inc	RMD	146.6274	235.88	34,586.47	0.09%	0.90%	0.00%	12.63%	0.01%
Mettler-Toledo International Inc	MTD	20.84095	1061.79	22,128.71	0.06%			8.14%	0.00%
VICI Properties Inc	VICI	1056.70255	32.22	34,046.96	0.09%	5.37%	0.00%	5.05%	0.00%
Copart Inc	CPRT	966.09296	60.9	58,835.06					
Jacobs Solutions Inc	J	122.54367	121.57	14,897.63	0.04%	1.05%	0.00%	12.70%	0.01%
Albemarle Corp	ALB	117.65057	57.73	6,791.97		2.81%		83.76%	
Fortinet Inc	FTNT	768.97406	101.8	78,281.56	0.21%			10.06%	0.02%
Moderna Inc	MRNA	386.6226	27.22	10,523.87				22.11%	
Essex Property Trust Inc	ESS	64.32558	275.5	17,721.70	0.05%	3.73%	0.00%	3.01%	0.00%
CoStar Group Inc	CSGP	421.76275	82.82	34,930.39				40.81%	
Realty Income Corp	O	891.76916	56.89	50,732.75	0.14%	5.66%	0.01%	3.67%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	171.12633	184.03	31,492.38	0.09%	0.54%	0.00%	15.51%	0.01%
Palantir Technologies Inc	PLTR	2262.68277	112.78	255,185.36				32.33%	
Pool Corp	POOL	37.7182	291.59	10,998.25	0.03%	1.71%	0.00%	6.39%	0.00%
Western Digital Corp	WDC	347.8239	40.78	14,184.26		0.98%			
PepsiCo Inc	PEP	1371.07954	133.38	182,874.59	0.50%	4.27%	0.02%	3.13%	0.02%
TE Connectivity PLC	TEL	298.35318	144.37	43,073.25	0.12%	1.97%	0.00%	8.35%	0.01%
Diamondback Energy Inc	FANG	294.08295	136.76	40,218.78		2.92%		-9.04%	
Palo Alto Networks Inc	PANW	662.1	178.98	118,502.66	0.32%			14.73%	0.05%
ServiceNow Inc	NOW	207	945.26	195,668.82					
Church & Dwight Co Inc	CHD	246.109	99.31	24,441.08	0.07%	1.19%	0.00%	6.71%	0.00%
Federal Realty Investment Trust	FRT	85.78007	94.38	8,095.92	0.02%	4.66%	0.00%	3.86%	0.00%
MGM Resorts International	MGM	282.95059	31.67	8,961.05	0.02%			7.19%	0.00%
American Electric Power Co Inc	AEP	533.98769	106.74	56,997.85	0.16%	3.49%	0.01%	5.10%	0.01%
Invitation Homes Inc	INVH	612.88313	33.78	20,703.19	0.06%	3.43%	0.00%	3.59%	0.00%
PTC Inc	PTC	120.32354	154.03	18,533.43	0.05%			16.34%	0.01%
JB Hunt Transport Services Inc	JBHT	99.19459	129.73	12,868.51	0.04%	1.36%	0.00%	14.67%	0.01%
Lam Research Corp	LRCX	1283.662	71.42	91,679.14	0.25%	1.29%	0.00%	17.27%	0.04%
Mohawk Industries Inc	MHK	62.5156	106.87	6,681.04	0.02%			3.61%	0.00%
GE HealthCare Technologies Inc	GEHC	457.84319	68.42	31,325.63	0.09%	0.20%	0.00%	6.15%	0.01%

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.
Pentair PLC	PNR	164.527	90	14,807.43	0.04%	1.11%	0.00%	9.53%	0.00%
Vertex Pharmaceuticals Inc	VRTX	257.08084	493.84	126,956.80					
Amcor PLC	AMCR	1445.34321	9.54	13,788.57	0.04%	5.35%	0.00%	4.99%	0.00%
Meta Platforms Inc	META	2181.2704	547.27	1,193,743.85	3.25%	0.38%	0.01%	14.45%	0.47%
T-Mobile US Inc	TMUS	1135.44511	232.77	264,297.56		1.51%			
United Rentals Inc	URI	64.99904	633.6	41,183.39	0.11%	1.13%	0.00%	6.76%	0.01%
Alexandria Real Estate Equities Inc	ARE	172.98904	75.88	13,126.41	0.04%	6.96%	0.00%	1.29%	0.00%
Honeywell International Inc	HON	643.25697	199.16	128,111.06	0.35%	2.27%	0.01%	7.57%	0.03%
Delta Air Lines Inc	DAL	652.95517	41.58	27,149.88	0.07%	1.44%	0.00%	1.02%	0.00%
United Airlines Holdings Inc	UAL	327.70387	68.2	22,349.40	0.06%			4.96%	0.00%
Seagate Technology Holdings PLC	STX	211.70739	82.7	17,508.20		3.48%		111.36%	
News Corp	NWS	189.34085	31.23	5,913.11		0.64%			
Centene Corp	CNC	497.603	57.69	28,706.72	0.08%			7.97%	0.01%
Apollo Global Management Inc	APO	570.48047	133.4	76,102.09	0.21%	1.53%	0.00%	12.87%	0.03%
Martin Marietta Materials Inc	MLM	60.60029	504.44	30,569.21		0.63%			
Teradyne Inc	TER	161.53887	77.12	12,457.88	0.03%	0.62%	0.00%	7.23%	0.00%
PayPal Holdings Inc	PYPL	977.39513	65.34	63,863.00	0.17%			12.15%	0.02%
Tesla Inc	TSLA	3220.95621	284.95	917,811.47					
Blackrock Inc	BLK	155.02206	907.69	140,711.97	0.38%	2.30%	0.01%	2.09%	0.01%
KKR & Co Inc	KKR	888.25053	113.63	100,931.91		0.65%			
Arch Capital Group Ltd	ACGL	375.71602	90.68	34,069.93	0.09%			1.83%	0.00%
Dow Inc	DOW	705.76446	30.02	21,187.05	0.06%	9.33%	0.01%	14.77%	0.01%
Everest Group Ltd	EG	47.78488	353.15	16,875.23		2.27%		28.16%	
Teledyne Technologies Inc	TDY	46.8373	458.6	21,479.59	0.06%			9.92%	0.01%
Domino's Pizza Inc	DPZ	34.29704	487.58	16,722.55	0.05%	1.43%	0.00%	9.09%	0.00%
GE Vernova Inc	GEV	272.93474	372.42	101,646.36		0.27%		97.71%	
News Corp	NWSA	378.05509	27.13	10,256.63		0.74%			
Exelon Corp	EXC	1009.53563	46.22	46,660.74	0.13%	3.46%	0.00%	8.10%	0.01%
Global Payments Inc	GPN	245.87628	72.48	17,821.11	0.05%	1.38%	0.00%	9.10%	0.00%
Crown Castle Inc	CCI	435.43378	100.19	43,626.11		4.24%		32.66%	
Align Technology Inc	ALGN	73.21033	183.35	13,423.11	0.04%			11.22%	0.00%
Kenvue Inc	KVUE	1918.69118	23.01	44,149.08		3.56%		35.21%	
Targa Resources Corp	TRGP	217.58533	177.62	38,647.51		2.25%			
Bunge Global SA	BG	133.96805	80.91	10,839.35	0.03%	3.46%	0.00%	2.61%	0.00%
LKQ Corp	LKQ	258.14768	37.41	9,657.30		3.21%			
Deckers Outdoor Corp	DECK	151.77364	109.19	16,572.16	0.05%			16.41%	0.01%
Workday Inc	WDAY	216.63533	239.53	51,890.66					
Zoetis Inc	ZTS	446.17999	153.47	68,475.24	0.19%	1.30%	0.00%	8.92%	0.02%
Equinix Inc	EQIX	97.81826	838.1	81,981.48		2.24%		29.36%	
Digital Realty Trust Inc	DLR	336.74872	159.88	53,839.39	0.15%	3.05%	0.00%	6.61%	0.01%
Molina Healthcare Inc	MOH	54.2	314.51	17,046.44	0.05%			11.34%	0.01%
Las Vegas Sands Corp	LVS	706.62756	35.89	25,360.86	0.07%	2.79%	0.00%	5.45%	0.00%

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 30, 2025
[5] Bloomberg Professional as of May 30, 2025
[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 30, 2025
[9] Equals [7] x [8]
[10] Bloomberg Professional, as of May 30, 2025
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9144356
R Square	0.8361925
Adjusted R Square	0.8352824
Standard Error	0.0057682
Observations	182

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03057	0.03057	918.85070	0.00000
Residual	180	0.00599	0.00003		
Total	181	0.03656			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0803	0.00	84.12	0.0000	0.0784	0.0821	0.0784	0.0821
U.S. Govt. 30-year Treasury	(0.4285)	0.01	(30.31)	0.0000	(0.4564)	(0.4006)	(0.4564)	(0.4006)

	[7] U.S. Govt. 30-year Treasury [7]	[8] Risk Premium [8]	[9] ROE [9]
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.86%	5.94%	10.80%
Blue Chip Near-Term Projected Forecast (Q3 2025 - Q3 2026) [5]	4.60%	6.05%	10.65%
Blue Chip Long-Term Projected Forecast (2027-2031) [6]	4.40%	6.14%	10.54%
AVERAGE			10.67%

Notes:
[1] Source: Regulatory Research Associates, rate cases through May 30, 2025
[2] Source: 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] Source: S&P Capital IQ Pro, 30-day average as of May 30, 2025
[5] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.080254 + (-0.428533 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1980.1	13.97%	11.66%	2.31%
1980.2	14.25%	10.52%	3.73%
1980.3	14.30%	10.85%	3.45%
1980.4	14.32%	12.10%	2.23%
1981.1	14.82%	12.53%	2.28%
1981.2	15.05%	13.24%	1.81%
1981.3	15.31%	14.13%	1.17%
1981.4	15.59%	13.85%	1.74%
1982.1	15.71%	13.96%	1.75%
1982.2	15.60%	13.52%	2.08%
1982.3	15.85%	12.79%	3.06%
1982.4	16.03%	10.75%	5.28%
1983.1	15.54%	10.71%	4.83%
1983.2	15.13%	10.65%	4.48%
1983.3	15.39%	11.62%	3.77%
1983.4	15.37%	11.74%	3.63%
1984.1	15.06%	12.04%	3.02%
1984.2	15.18%	13.18%	2.00%
1984.3	15.38%	12.69%	2.69%
1984.4	15.69%	11.70%	3.99%
1985.1	15.48%	11.58%	3.90%
1985.2	15.27%	11.00%	4.27%
1985.3	14.84%	10.55%	4.29%
1985.4	15.11%	10.04%	5.07%
1986.1	14.42%	8.77%	5.65%
1986.2	14.27%	7.49%	6.78%
1986.3	13.26%	7.40%	5.86%
1986.4	13.52%	7.53%	5.99%
1987.1	12.90%	7.49%	5.40%
1987.2	13.17%	8.53%	4.64%
1987.3	13.14%	9.06%	4.08%
1987.4	12.76%	9.23%	3.53%
1988.1	12.74%	8.63%	4.11%
1988.2	12.70%	9.06%	3.63%
1988.3	12.78%	9.18%	3.60%
1988.4	12.97%	8.97%	4.00%
1989.1	13.02%	9.04%	3.99%
1989.2	13.22%	8.70%	4.52%
1989.3	12.38%	8.12%	4.26%
1989.4	12.83%	7.93%	4.90%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1990.1	12.62%	8.44%	4.19%
1990.2	12.85%	8.65%	4.20%
1990.3	12.54%	8.79%	3.75%
1990.4	12.68%	8.56%	4.12%
1991.1	12.66%	8.20%	4.46%
1991.2	12.67%	8.31%	4.36%
1991.3	12.49%	8.19%	4.30%
1991.4	12.42%	7.85%	4.57%
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.72%	4.65%
1995.4	11.58%	6.24%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.53%	5.23%
2001.4	11.99%	5.30%	6.69%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.65%	5.09%	6.56%
2002.4	11.57%	4.93%	6.63%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	11.24%	4.93%	6.31%
2005.1	10.63%	4.71%	5.92%
2005.2	10.31%	4.47%	5.84%
2005.3	11.08%	4.42%	6.66%
2005.4	10.63%	4.65%	5.98%
2006.1	10.70%	4.63%	6.07%
2006.2	10.79%	5.14%	5.64%
2006.3	10.35%	5.00%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.79%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.96%
2008.3	10.43%	4.45%	5.98%
2008.4	10.39%	3.64%	6.74%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.25%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.37%	5.81%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.20%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.70%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.94%	7.01%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.16%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.27%	6.63%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.05%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2019.1	9.72%	3.01%	6.70%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.25%
2019.4	9.89%	2.26%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.19%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.26%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.69%	1.95%	7.74%
2022.1	9.45%	2.25%	7.20%
2022.2	9.50%	3.05%	6.45%
2022.3	9.14%	3.26%	5.88%
2022.4	9.94%	3.89%	6.04%
2023.1	9.72%	3.75%	5.97%
2023.2	9.67%	3.81%	5.86%
2023.3	9.79%	4.23%	5.55%
2023.4	9.85%	4.58%	5.27%
2024.1	9.67%	4.32%	5.35%
2024.2	9.90%	4.58%	5.32%
2024.3	9.88%	4.23%	5.65%
2024.4	9.90%	4.50%	5.40%
2025.1	9.83%	4.72%	5.11%
2025.2	9.42%	4.81%	4.60%
AVERAGE	11.47%	6.03%	5.44%
MEDIAN	11.00%	5.13%	5.60%

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization

Company	Ticker	[1] Market Capitalization ($ billions)
Alliant Energy Corporation	LNT	15.75
Ameren Corporation	AEE	26.39
American Electric Power Company, Inc.	AEP	55.90
Avista Corporation	AVA	3.22
CMS Energy Corporation	CMS	21.46
Dominion Resources, Inc.	D	46.79
DTE Energy Company	DTE	28.20
Duke Energy Corporation	DUK	92.24
Entergy Corporation	ETR	35.77
Evergy, Inc.	EVRG	15.48
IDACORP, Inc.	IDA	6.27
NextEra Energy, Inc.	NEE	141.51
NorthWestern Corporation	NWE	3.49
OGE Energy Corporation	OGE	8.97
Pinnacle West Capital Corporation	PNW	11.03
Portland General Electric Company	POR	4.63
PPL Corporation	PPL	26.12
Southern Company	SO	98.84
Xcel Energy Inc.	XEL	40.52
Median		26.12

Montana-Dakota		
Test Year Rate Base ($millions)	[2]	$ 101.19
Company-Projected Common Equity Ratio	[3]	51.09%
Common Equity ($millions)	[4]	$51.69
Market Capitalization of Proxy Group (median) ($millions)	[5]	$26,120.09

Kroll Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10	[6] Market Capitalization of Largest Company ($ millions)	[7] Size Premium
1-Largest	3,522,211.14	-0.01%
2	46,949.06	0.33%
3	20,178.36	0.49%
4	9,937.35	0.50%
5	6,181.27	0.74%
6	3,946.15	1.00%
7	2,464.50	1.19%
8	1,417.45	0.88%
9	729.92	1.73%
10-Smallest	304.48	4.47%

Montana-Dakota - Common Equity	[4]	51.69	4.47%
Proxy Group Market Capitalization (median)	[5]	26,120.09	0.33%
Size Premium	[8]		4.14%

Notes:
[1] S&P Capital IQ Pro, equals 30-day average as of May 30, 2025
[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 12/31/2024
[8] Size Premium of the Company 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 Projected EPS Growth Rate	[16] Zacks Projected EPS Growth Rate	[17] S&P Capital IQ Projected EPS Growth Rate	[18] Average Earnings Growth	[19] Cost of Equity: Mean Growth Rate	[20] Cost of Equity Adjusted for Flotation Costs	
Alliant Energy Corporation	LNT	$ 2.03	$ 61.19	3.32%	3.42%	3.55%	6.00%	6.60%	6.54%	6.38%	9.80%	9.93%	
Ameren Corporation	AEE	$ 2.84	$ 97.64	2.91%	3.01%	3.12%	6.50%	7.00%	6.95%	6.82%	9.82%	9.94%	
American Electric Power Company, Inc.	AEP	$ 3.72	$ 104.28	3.57%	3.68%	3.83%	6.50%	6.40%	6.80%	6.57%	10.25%	10.39%	
Avista Corporation	AVA	$ 1.96	$ 39.73	4.93%	5.08%	5.27%	5.50%	6.10%	5.98%	5.86%	10.94%	11.13%	
CMS Energy Corporation	CMS	$ 2.17	$ 71.46	3.04%	3.14%	3.26%	6.00%	7.80%	7.31%	7.04%	10.18%	10.30%	
Dominion Resources, Inc.	D	$ 2.67	$ 54.27	4.92%	5.17%	5.37%	6.00%	13.60%	11.39%	10.33%	15.50%	15.70%	
DTE Energy Company	DTE	$ 4.36	$ 135.92	3.21%	3.31%	3.44%	4.50%	7.60%	7.62%	6.57%	9.89%	10.01%	
Duke Energy Corporation	DUK	$ 4.18	$ 117.97	3.54%	3.65%	3.79%	6.00%	6.30%	6.38%	6.23%	9.88%	10.02%	
Entergy Corporation	ETR	$ 2.40	$ 82.84	2.90%	3.00%	3.12%	3.00%	9.50%	9.12%	7.21%	10.21%	10.32%	
Evergy, Inc.	EVRG	$ 2.67	$ 66.71	4.00%	4.13%	4.29%	7.50%	5.70%	5.70%	6.30%	10.43%	10.59%	
IDACORP, Inc.	IDA	$ 3.44	$ 115.84	2.97%	3.08%	3.20%	6.00%	8.10%	8.09%	7.40%	10.48%	10.59%	
NextEra Energy, Inc.	NEE	$ 2.27	$ 68.19	3.32%	3.46%	3.59%	8.50%	7.70%	7.81%	8.00%	11.46%	11.59%	
NorthWestern Corporation	NWE	$ 2.64	$ 56.85	4.64%	4.78%	4.96%	4.50%	6.90%	5.80%	5.73%	10.51%	10.69%	
OGE Energy Corporation	OGE	$ 1.69	$ 44.56	3.78%	3.90%	4.05%	6.50%	6.30%	6.53%	6.44%	10.35%	10.50%	
Pinnacle West Capital Corporation	PNW	$ 3.58	$ 92.11	3.89%	3.96%	4.12%	5.00%	2.10%	4.76%	3.95%	7.92%	8.07%	
Portland General Electric Company	POR	$ 2.00	$ 42.29	4.73%	4.84%	5.03%	6.50%	3.40%	4.76%	4.89%	9.73%	9.92%	
PPL Corporation	PPL	$ 1.09	$ 35.34	3.08%	3.20%	3.32%	7.50%	7.50%	7.40%	7.47%	10.67%	10.79%	
Southern Company	SO	$ 2.96	$ 89.40	3.31%	3.42%	3.55%	6.50%	6.50%	6.29%	6.43%	9.85%	9.98%	
Xcel Energy Inc.	XEL	$ 2.28	$ 70.26	3.25%	3.37%	3.49%	7.00%	7.50%	7.73%	7.41%	10.78%	10.90%	
Mean											10.45%	10.60%	
Median											10.25%	10.39%	
Flotation Cost Adjustment (Mean)												0.14%	[21]
Flotation Cost Adjustment (Median)												0.14%	[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 30, 2025
[12] Equals [10] / [11]
[13] Equals [12] x (1 + 0.5 x [18])
[14] Equals [13] / (1 − Flotation Cost)
[15] Value Line
[16] Zacks Investment Research
[17] S&P Capital IQ
[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)

2025-2029 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2024	2025	2026	2027	2028	2029	2025-29 Cap. Ex. / 2024 Net Plant
Alliant Energy Corporation	LNT							
Capital Spending per Share			$5.60	$5.60	$5.50	$5.40	$5.40	
Common Shares Outstanding			256.70	257.00	257.00	257.00	257.00	
Capital Expenditures			$1,437.5	$1,439.2	$1,413.5	$1,387.8	$1,387.8	37.78%
Net Plant		$18,701.0						
Ameren Corporation	AEE							
Capital Spending per Share			$12.80	$12.85	$12.93	$13.00	$13.00	
Common Shares Outstanding			272.00	275.00	280.00	285.00	285.00	
Capital Expenditures			$3,481.6	$3,533.8	$3,619.0	$3,705.0	$3,705.0	49.61%
Net Plant		$36,376.0						
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			$14.10	$14.10	$14.05	$14.00	$14.00	
Common Shares Outstanding			535.00	540.00	545.00	550.00	550.00	
Capital Expenditures			$7,543.5	$7,614.0	$7,657.3	$7,700.0	$7,700.0	46.37%
Net Plant		$82,416.0						
Avista Corporation	AVA							
Capital Spending per Share			$6.60	$7.00	$7.88	$8.75	$8.75	
Common Shares Outstanding			81.00	83.00	84.00	85.00	85.00	
Capital Expenditures			$534.6	$581.0	$661.5	$743.8	$743.8	54.23%
Net Plant		$6,020.0						
CMS Energy Corporation	CMS							
Capital Spending per Share			$12.75	$10.00	$10.00	$10.00	$10.00	
Common Shares Outstanding			300.00	301.00	301.50	302.00	302.00	
Capital Expenditures			$3,825.0	$3,010.0	$3,015.0	$3,020.0	$3,020.0	57.86%
Net Plant		$27,461.0						
D Dominion Resources, Inc.	D							
Capital Spending per Share			$12.40	$11.00	$11.00	$11.00	$11.00	
Common Shares Outstanding			855.00	858.00	869.00	880.00	880.00	
Capital Expenditures			$10,602.0	$9,438.0	$9,559.0	$9,680.0	$9,680.0	71.10%
Net Plant		$68,862.0						
DTE Energy Company	DTE							
Capital Spending per Share			$17.75	$17.95	$18.23	$18.50	$18.50	
Common Shares Outstanding			205.50	205.50	205.75	206.00	206.00	
Capital Expenditures			$3,647.6	$3,688.7	$3,749.8	$3,811.0	$3,811.0	60.19%
Net Plant		$31,081.0						

2025-2029 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2024	2025	2026	2027	2028	2029	2025-29 Cap. Ex. / 2024 Net Plant
Duke Energy Corporation	DUK							
Capital Spending per Share			$16.30	$16.75	$17.50	$18.25	$18.25	
Common Shares Outstanding			777.00	778.00	779.00	780.00	780.00	
Capital Expenditures			$12,665.1	$13,031.5	$13,632.5	$14,235.0	$14,235.0	54.99%
Net Plant		$123,303.0						
Entergy Corporation	ETR							
Capital Spending per Share			$12.00	$12.50	$13.25	$14.00	$14.00	
Common Shares Outstanding			435.00	440.00	450.00	460.00	460.00	
Capital Expenditures			$5,220.0	$5,500.0	$5,962.5	$6,440.0	$6,440.0	62.34%
Net Plant		$47,423.0						
Evergy, Inc.	EVRG							
Capital Spending per Share			$9.30	$9.35	$9.43	$9.50	$9.50	
Common Shares Outstanding			230.00	230.00	230.00	230.00	230.00	
Capital Expenditures			$2,139.0	$2,150.5	$2,167.8	$2,185.0	$2,185.0	44.74%
Net Plant		$24,200.0						
IDACORP, Inc.	IDA							
Capital Spending per Share			$18.50	$21.00	$22.00	$23.00	$23.00	
Common Shares Outstanding			54.00	55.00	$55.50	56.00	56.00	
Capital Expenditures			$999.0	$1,155.0	$1,221.0	$1,288.0	$1,288.0	90.56%
Net Plant		$6,571.3						
NextEra Energy, Inc.	NEE							
Capital Spending per Share			$11.00	$11.00	$11.50	$12.00	$12.00	
Common Shares Outstanding			2065.00	2100.00	2150.00	2200.00	2200.00	
Capital Expenditures			$22,715.0	$23,100.0	$24,725.0	$26,400.0	$26,400.0	88.83%
Net Plant		$138,852.0						
NorthWestern Corporation	NWE							
Capital Spending per Share			$8.45	$8.50	8.63	$8.75	$8.75	
Common Shares Outstanding			62.00	62.50	63.25	64.00	64.00	
Capital Expenditures			$523.9	$531.3	$545.5	$560.0	$560.0	42.52%
Net Plant		$6,398.3						
OGE Energy Corporation	OGE							
Capital Spending per Share			$4.75	$4.75	$4.75	$4.75	$4.75	
Common Shares Outstanding			200.20	200.20	200.20	200.20	200.20	
Capital Expenditures			$951.0	$951.0	$951.0	$951.0	$951.0	41.21%
Net Plant		$11,538.0						

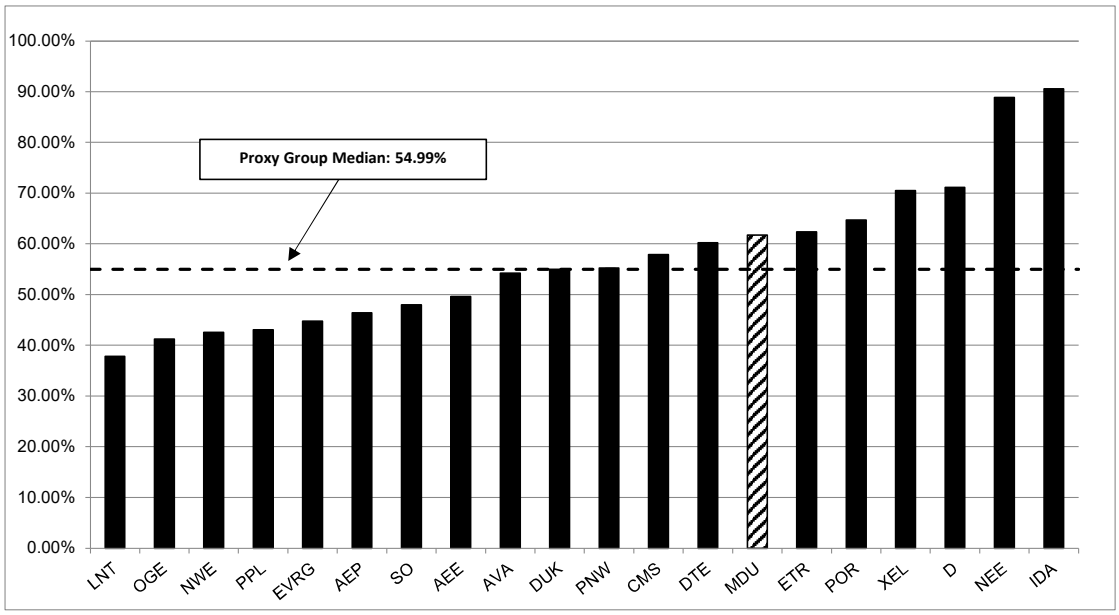
2025-2029 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2024	2025	2026	2027	2028	2029	2025-29 Cap. Ex. / 2024 Net Plant
Pinnacle West Capital Corporation	PNW							
Capital Spending per Share			$16.75	$17.00	$17.25	$17.50	$17.50	
Common Shares Outstanding			120.50	122.00	123.50	125.00	125.00	
Capital Expenditures			$2,018.4	$2,074.0	$2,130.4	$2,187.5	$2,187.5	55.20%
Net Plant		$19,198.0						
Portland General Electric Company	POR							
Capital Spending per Share			$11.50	$11.50	$11.50	$11.50	$11.50	
Common Shares Outstanding			111.00	114.00	117.00	120.00	120.00	
Capital Expenditures			$1,276.5	$1,311.0	$1,345.5	$1,380.0	$1,380.0	64.70%
Net Plant		$10,345.0						
PPL Corporation	PPL							
Capital Spending per Share			$3.70	$3.75	$3.88	$4.00	$4.00	
Common Shares Outstanding			737.40	737.50	737.75	738.00	738.00	
Capital Expenditures			$2,728.4	$2,765.6	$2,858.8	$2,952.0	$2,952.0	43.01%
Net Plant		$33,149.0						
Southern Company	SO							
Capital Spending per Share			$8.75	$8.70	$8.60	$8.50	$8.50	
Common Shares Outstanding			1,105.00	1110.00	1115.00	1120.00	1120.00	
Capital Expenditures			$9,668.8	$9,657.0	$9,589.0	$9,520.0	$9,520.0	47.94%
Net Plant		$100,028.0						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$15.00	$14.00	$13.50	$13.00	$13.00	
Common Shares Outstanding			580.00	585.00	590.00	595.00	595.00	
Capital Expenditures			$8,700.0	$8,190.0	$7,965.0	$7,735.0	$7,735.0	70.50%
Net Plant		$57,198.0						
Montana-Dakota Utilities Co.	MDU							
Capital Expenditures [8]			$14.49	$9.84	$28.99	$8.07	$8.09	61.75%
Net Electric Plant in Service [9]		$112.511						

MDU WY CapEx Total (2025-2029)	$69.48
MDU WY CapEx Annual Average	$14
Proxy Group Median	55.0%
MDU WY as % Proxy Group Median	1.12

Notes:
[1] - [6] Value Line dated March 7, 2025 , April 18, 2025, and May 9, 2025.
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] - [9] Data provided by Montana-Dakota

2025-2029 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT



	Company		2025-2029
1	Alliant Energy Corporation	LNT	37.78%
2	OGE Energy Corporation	OGE	41.21%
3	NorthWestern Corporation	NWE	42.52%
4	PPL Corporation	PPL	43.01%
5	Evergy, Inc.	EVRG	44.74%
6	American Electric Power Company, Inc.	AEP	46.37%
7	Southern Company	SO	47.94%
8	Ameren Corporation	AEE	49.61%
9	Avista Corporation	AVA	54.23%
10	Duke Energy Corporation	DUK	54.99%
11	Pinnacle West Capital Corporation	PNW	55.20%
12	CMS Energy Corporation	CMS	57.86%
13	DTE Energy Company	DTE	60.19%
14	Montana-Dakota Utilities Co.	MDU	61.75%
15	Entergy Corporation	ETR	62.34%
16	Portland General Electric Company	POR	64.70%
17	Xcel Energy Inc.	XEL	70.50%
18	D	D	71.10%
19	NextEra Energy, Inc.	NEE	88.83%
20	IDACORP, Inc.	IDA	90.56%
	Proxy Group Median		54.99%
	MDU / Proxy Group		1.12

Notes:
Source: Exhibit No. ___(AEB-2), Schedule 11

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Stabilization: Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Revenue Stabilization: Overall Revenue Stabilization	[6] Capital Cost Recovery
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Fully Forecast	No	No	No	No	Yes
	Interstate Power & Light Co.	Iowa	Gas	Fully Forecast	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Union Electric Co.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
	Union Electric Co.	Missouri	Gas	Historical	Yes	No	No	Yes	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Historical	Yes	No	No	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	Yes	Yes	No	Yes	No
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Ohio Power Co.	Ohio	Electric	Partially Forecast	Yes	No	No	Yes	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Historical	No	No	No	No	No
	AEP Texas	Texas	Electric	Historical	No	No	No	No	Yes
	Southwestern Electric Power Co.	Texas	Electric	Historical	No	No	No	No	Yes
	Appalachian Power Co.	Virginia	Electric	Historical	No	No	No	No	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Historical	No	No	No	No	Yes
Avista Corporation	Alaska Electric Light and Power Co.	Alaska	Electric	Historical	No	No	No	No	No
	Avista Corp.	Idaho	Electric	Historical	Yes	No	No	Yes	No
	Avista Corp.	Idaho	Gas	Historical	Yes	No	No	Yes	No
	Avista Corp.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	No
	Avista Corp.	Washington	Electric	Historical	Yes	No	No	Yes	No
	Avista Corp.	Washington	Gas	Historical	Yes	No	No	Yes	No
CMS Energy Corporation	Consumers Energy Co.	Michigan	Electric	Fully Forecast	No	No	No	No	Yes
	Consumers Energy Co.	Michigan	Gas	Fully Forecast	Yes	No	No	Yes	No
Dominion Resources, Inc.	Dominion Energy Virginia	North Carolina	Electric	Historical	Yes	No	No	Yes	Yes
	Dominion Energy South Carolina	South Carolina	Electric	Historical	No	No	No	No	Yes
	Dominion Energy South Carolina	South Carolina	Gas	Historical	Yes	No	No	Yes	Yes
	Dominion Energy Virginia	Virginia	Electric	Partially Forecast	No	No	No	No	Yes
DTE Energy Company	DTE Electric Co.	Michigan	Electric	Fully Forecast	No	No	No	No	Yes
	DTE Gas Co.	Michigan	Gas	Fully Forecast	Yes	No	No	Yes	Yes
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Fully Forecast	No	No	No	No	Yes
	Duke Energy Indiana LLC	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	Historical	No	No	No	No	Yes
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Historical	Yes	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	Partially Forecast	Yes	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	South Carolina	Electric	Historical	No	No	No	No	Yes
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Historical	Yes	No	No	Yes	No
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	Historical	Yes	No	No	Yes	Yes
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Partially Forecast	No	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Partially Forecast	No	Yes	No	Yes	No
	Entergy Louisiana LLC	Louisiana	Electric	Historical	Yes	Yes	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	No	Yes	No	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	Yes	Yes	No	Yes	No
	Entergy Texas Inc.	Texas	Electric	Fully Forecast	No	No	No	No	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Metro Inc.	Kansas	Electric	Historical	No	No	No	No	Yes
	Evergy Metro Inc	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Missouri West Inc.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Partially Forecast	Yes	No	No	Yes	No
	Idaho Power Co.	Oregon	Electric	Partially Forecast	No	No	No	No	No
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Fully Forecast	No	No	No	No	Yes
	Pivotal Utility Holdings Inc.	Florida	Gas	Fully Forecast	No	No	No	No	Yes
	Lone Star Transmission LLC	Texas	Electric	Historical	No	No	No	No	Yes
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	Historical	No	No	No	No	No
	NorthWestern Corporation	Montana	Gas	Historical	No	No	No	No	No

Docket No. 20004-___-ER-25
Exhibit No. ___(AEB-2)
Schedule 12
Page 1

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
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
	NorthWestern Corporation	Nebraska	Gas	Historical	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Electric	Historical	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Gas	Historical	No	No	No	No	No
OGE Energy Corporation	Oklahoma Gas and Electric Company	Arkansas	Electric	Historical	Yes	Yes	No	Yes	Yes
	Oklahoma Gas and Electric Company	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes
Pinnacle West Capital Corporation	Arizona Public Service Co.	Arizona	Electric	Historical	Yes	No	No	Yes	Yes
Portland General Electric Company	Portland General Electric Co.	Oregon	Electric	Fully Forecast	No	No	No	No	Yes
PPL Corporation	Kentucky Utilities Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Louisville Gas & Electric Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Louisville Gas & Electric Co.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	PPL Electric Utilities Corp.	Pennsylvania	Electric	Fully Forecast	No	No	No	No	Yes
	Narragansett Electric Co.	Rhode Island	Electric	Historical	Yes	No	No	Yes	Yes
	Narragansett Electric Co.	Rhode Island	Gas	Historical	Yes	No	No	Yes	Yes
	Kentucky Utilities Co.	Virginia	Electric	Historical	No	No	No	No	No
Southern Company	Alabama Power Co.	Alabama	Electric	Fully Forecast	No	Yes	No	Yes	Yes
	Georgia Power Co.	Georgia	Electric	Fully Forecast	No	Yes	No	Yes	Yes
	Atlanta Gas & Light Co.	Georgia	Gas	Fully Forecast	No	Yes	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Historical	Yes	Yes	No	Yes	No
	Virginia Natural Gas Inc.	Virginia	Gas	Partially Forecast	Yes	No	No	Yes	Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Historical	Yes	No	No	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Yes	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	Fully Forecast	No	No	No	No	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Electric	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Fully Forecast	No	No	Yes	Yes	No
	Northern States Power Co.-Minnesota	South Dakota	Electric	Historical	Yes	No	No	Yes	Yes
	Southwestern Public Service Co.	Texas	Electric	Historical	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Fully Forecast	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No	No
Proxy Group Totals				Fully Forecast 40					
				Partially Forecast 9				Yes 58	Yes 67
				Historical 46				No 37	No 28
				% Forecast 51.58%				% Yes 61.05%	% Yes 70.53%
Montana-Dakota [7]		Wyoming	Electric	Historical	Partial	No	No	Yes	Proposed

Notes:
[1] Regulatory Research Associates, effective as of May 30, 2025.
[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. A designation of "Yes" indicates full or partial decoupling.
[3] S&P Capital IQ Pro, Alternative Regulation
[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. Yes, if noted by S&P as a having a capital tracker to recover either "Traditional generation", "Renewables/Non-traditional generation", "Delivery infrastructure", or "Environmental compliance".
[7] Company Provided Information

CAPITAL STRUCTURE ANALYSIS

		Most Recent 8 Quarters (2023Q1 - 2024Q4)				
Proxy Group Company	Ticker	Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Short-Term Debt Ratio	Total Capitalization
Alliant Energy Corporation	LNT	51.64%	47.67%	0.00%	0.69%	100.00%
Ameren Corporation	AEE	52.08%	45.43%	0.49%	2.00%	100.00%
American Electric Power Company, Inc.	AEP	47.63%	50.66%	0.00%	1.71%	100.00%
Avista Corporation	AVA	47.40%	47.84%	0.00%	4.76%	100.00%
CMS Energy Corporation	CMS	48.61%	50.59%	0.17%	0.63%	100.00%
Dominion Resources, Inc.	D	50.57%	43.78%	0.00%	5.65%	100.00%
DTE Energy Company	DTE	48.25%	49.72%	0.00%	2.03%	100.00%
Duke Energy Corporation	DUK	51.49%	46.38%	0.00%	2.13%	100.00%
Entergy Corporation	ETR	50.70%	49.20%	0.09%	0.00%	100.00%
Evergy, Inc.	EVRG	56.71%	37.10%	0.00%	6.19%	100.00%
IDACORP, Inc.	IDA	50.25%	49.75%	0.00%	0.00%	100.00%
NextEra Energy, Inc.	NEE	58.67%	39.26%	0.00%	2.07%	100.00%
NorthWestern Corporation	NWE	50.37%	49.63%	0.00%	0.00%	100.00%
OGE Energy Corporation	OGE	52.98%	46.36%	0.00%	0.66%	100.00%
Pinnacle West Capital Corporation	PNW	48.91%	48.07%	0.00%	3.02%	100.00%
Portland General Electric Company	POR	45.33%	54.05%	0.00%	0.63%	100.00%
PPL Corporation	PPL	55.54%	43.09%	0.00%	1.37%	100.00%
Southern Company	SO	54.70%	43.77%	0.00%	1.52%	100.00%
Xcel Energy Inc.	XEL	53.76%	45.41%	0.00%	0.83%	100.00%
Average		51.35%	46.72%	0.04%	1.89%	
Median		50.70%	47.67%	0.00%	1.52%	
Maximum		58.67%	54.05%	0.49%	6.19%	
Minimum		45.33%	37.10%	0.00%	0.00%	

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of the operating subsidiaries.
[2] Electric and natural gas operating subsidiaries with data listed as N/A from S&P Capital IQ Pro have been excluded from the analysis.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Wyoming

Docket No. 20004-___-ER-25

Direct Testimony

Of

Daryl Anderson

Q. Please state your name and business address.

A. My name is Daryl Anderson, 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 Director of Electric Distribution Services for Montana-Dakota Utilities Co. (Montana-Dakota).

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

A. My responsibilities include oversight and management of the electric distribution operations and engineering support services, including electric operations systems, metering, electric engineering systems, electric engineering project construction & maintenance, and electric distribution standards and procedures.

Q. Please outline your educational and professional background.

A. I hold an Associates of Science Degree in Engineering from Minot State College and a Bachelor of Science in Electrical and Electronics Engineering from North Dakota State University. My work experience at Montana-Dakota includes six years as an Electrical Engineer working at various District locations, twelve years working as the Electric Superintendent in the Rocky Mountain Region, and seven years as the Director of Distribution Engineering with both gas and electric utility responsibilities. I assumed my current position in 2015. Prior to my work at Montana-Dakota I worked five and a half years as an Electric Engineer for a combination gas and electric utility located in Iowa.

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

A. Yes, I have testified before the Wyoming, Montana, and North Dakota Public Service Commissions and the South Dakota Public Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information regarding Montana-Dakota's proposed Reliability and Safety Infrastructure Rider Rate 55 (RSIR) Tariff. More specifically, to provide an explanation for two

of the projects related to the request, the benefits provided by the projects, and the estimated costs expected to relate to the RSIR proposal.

Q. What projects are planned to be associated with the proposed RSIR?

A. There are three multi-year projects that have a need to be addressed for the Company's Electric Distribution System (EDS) in the Wyoming service territory:

1. An Underground Vintage Cable Replacement Program;
2. Wildfire Risk Electric Distribution Mitigation Program; and
3. Sheridan to Dayton 41.6 kV line.

The overall goal of these projects is to increase service reliability and safety for customers and employees in Montana-Dakota's service territory. I am responsible for the Underground Vintage Cable Replacement Program and the Wildfire Risk Electric Distribution Mitigation Program; while the Sheridan to Dayton 41.6 kV line will be covered in the testimony of Mr. Robert Frank.

<u>Underground Vintage Cable Replacement Program</u>

Q. What is the Underground Vintage Cable Replacement Program?

A. Montana-Dakota started a program to replace all of the electric distribution primary voltage underground cables within its EDS many years ago due to cable failures. It first started modestly as a replacement

program to target failed cables in specific areas as they present reliability problems. As time has progressed the current program is directed to replace all electric distribution primary underground cables manufactured before 1985.

Q. Why has Montana-Dakota decided to replace all pre-1985 electric primary underground cables?

A. Montana-Dakota started installing primary electric distribution lines and systems underground as early as 1968. In the 1970's and early 1980's underground installations of electric distribution systems became fairly standard installations for new growth areas of the Wyoming service territory. These underground installations also presented many new benefits for safety and reliability. In the Wyoming service area for Montana-Dakota, replacement of older overhead systems with the new underground systems was viewed as an improvement in reliability due to outages and costs related to trees and vegetation management. Montana-Dakota, like most other electric utilities, saw the benefits to these new underground cable systems.

Then the cable failures started. Within the first 10 years of these cable installations, the cables started to fail due to pin hole faults in the insulation. These underground cable failures increased dramatically as

more and more cables were installed in the EDS. The entire utility industry and cable manufacture industry realized this issue by the early 1980's. Improvements in manufacturing processes and new materials solved the issue by 1985. Montana-Dakota and other utilities began installing improved cables made of better materials, better manufacture controls, external jackets, and new installation requirements.

For Montana-Dakota, the electric primary underground cables have an excellent reliability record starting with the new cables installed in 1985 and up to the current date. Electric primary underground cables installed prior to 1985 were comprised of a primary conductor covered by insulation and wrapped with a bare concentric copper neutral wire. There are two long-term problems with these early cable installations:

1. They will all fail at some point due to a breakdown with the early insulation materials, it is only a matter of time.
    a. Each cable failure does present a certain fire risk, where in a high fire danger environment weather event, a cable fault will result in a high voltage fuse operation that has some elevated fire risk.
2. Since the system neutral is bare to open earth, they have a tendency to corrode over time in some soils, leaving the conductor

without a neutral path in violation of the National Electrical Safety Code.

As a result, these early vintage pre-1985 electric primary underground cables have been determined by Montana-Dakota as a requirement for replacement due to their reliability and safety issues.

Q. What is the remaining work to be completed for the Underground Vintage Cable Replacement Program?

A. Montana-Dakota has been working to replace these cables as they have failed over the past 25 years or more. In more recent years, the determination to complete the replacement of all of these cables has become evident due to increased safety and reliability concerns as these cables continue to age. The total Montana-Dakota system had several million feet of these vintage cables in place in its system prior to 1985. Currently there remains approximately 450,000 feet of cables left to complete the program within the Montana-Dakota Wyoming service territory.

Q. What criteria does Montana-Dakota use to determine what cable is replaced each year?

A. With the decision to replace all of the remaining vintage cables within the EDS, the annual plan is to replace cables by distribution circuit.

This provides for the most efficiency to replace cables in subdivision areas common to a circuit where replacements are within the same general area so a communication plan for customers can be localized to specific areas.

Q. What are the capital costs involved with the completion of the Underground Vintage Cable Replacement Program?

A. The current capital costs requested in this case for 2025 are $1,706,066 for FP-325635 as shown on Statement B, Schedule B-2, page 2. Upon approval of the RSIR, the Company would file the rider as explained further in the testimony of Mr. Bradley Davison. The currently forecasted costs for 2026 and 2027 are:

	2026	**2027**
FP-325635	$1,787,372	$1,788,720

These annual capital costs for replacing the cables are based on the approved budget dollars within the given year. Montana-Dakota has historically averaged approximately $20 a foot for this project. It is expected that a total cost estimate to finish this program would be approximately $9,000,000 in today's dollars over the course of completion.

Q. How will Montana-Dakota customers benefit from this project?

A. Montana-Dakota customers will see improvement in reliability and safety from the replacement of the vintage underground cables. Reliability improvement from the elimination of cable failure faults on the distribution

system, which has average approximately 30 emergency power outages annually in Montana-Dakota's Wyoming service territory. Safety improvements from the reduction of wildfire risk from primary power fuse operations during a cable fault event and general system grounding safety to minimize the risk of isolated system grounds due to a corroded vintage cable neutrals.

Q. The project completion date is beyond 2025, why is this included?

A. Montana-Dakota will include this project within its proposed RSIR. This rider mechanism will allow reliability and risk reduction projects to be planned and executed by Montana-Dakota with the certainty of timely recovery.

Wildfire Risk Electric Distribution Mitigation Program

Q. What is the Wildfire Risk Distribution Mitigation Program?

A. Montana-Dakota is continuing to refine its Wildfire Risk Management Plan with the goal of a comprehensive plan for the electric operations. As a part of that overall plan, the EDS will require several targeted projects within that plan to reduce the risk of wildfire caused by electric facilities. In order to reduce risk, there are two main areas of concentration for the EDS facilities:

1. Configuring the EDS and equipment for real time operational changes based on situational awareness of current weather and fire hazard situations to reduce fire risks.
2. System hardening of the existing electric distribution lines by assessment and mitigation of fire risks associated with the existing lines.

Q. Explain what is meant by operational changes based on situational awareness?

A. The Montana-Dakota system operations group currently tracks weather-related warnings such as Red-Flag warnings and Fire Hazard Index information to require changes to the daily operations of the Company to help lower wildfire risks. Based on situational weather and wildfire risk information, Montana-Dakota intends to set up Non-Reclose Zones within its rural distribution system, where reclosers will be placed in a Non-Reclose operation based on situational awareness to lower the risk of wildfire starting from damages to the EDS under certain environmental conditions. In a Non-Reclose Zone, changes are made to the protective equipment to operate with reduced closing attempts after a system fault and possibly reduced fault energy to limit risks of starting a fire from

system damage events to the EDS. To set up these Non-Reclose Zones, there are capital costs involved.

Q. What is distribution system hardening to reduce wildfire risk?

A. Distribution system hardening is a term used for performing assessments and mitigation of existing distribution lines to lower the risk of the EDS equipment initiating a fire. The process for system hardening includes performing an assessment of each line section within the wildfire risk areas to make a determination on mitigation of the lines for risk reduction. Mitigation may include:

* Undergrounding line sections to eliminate overall fire risk; or
* Modifying existing overhead lines by eliminating obsolete equipment and bringing line sections up to newer construction standards to eliminate risk.

By assessing and mitigating the existing electric distribution lines in higher fire risk areas, the lines would reduce the wildfire likelihood risks as well as be made avian safe for eagles and large raptor birds.

Q. What is the overall scope of the Wildfire Risk Distribution Mitigation Program?

A. The Montana-Dakota EDS in Wyoming includes approximately 138 miles of Overhead Electric Distribution and 386 miles of Underground

Electric Distribution in the higher wildfire risk areas. These lines are operated by 27 circuits from various substations. The Wildfire Risk Distribution Mitigation Program will include creating Non-Reclose Zones for the 27 circuits and system hardening assessment and mitigation of the 138 miles of overhead distribution line sections within the higher wildfire risk areas.

Q. What criteria does Montana-Dakota use to determine what assessment and mitigation areas are planned to be addressed each year?

A. At Montana-Dakota, the refinement of the overall Wildfire Risk Management Plan includes a wildfire risk model to determine where the Company's facilities have the highest wildfire risks. This wildfire risk model will develop overall risk scores, by consequence and likelihood factors, to determine the relative risk of the Company's facilities by location. The higher wildfire risk EDS circuits, determined by the risk model, will be used to prioritize projects for each planned year of the process. In 2025, the Company has started to perform facility hardening assessments and situational awareness changes in the Story, Wyoming area along with several areas of the Big Horn Mountain forested areas as a high fire risk starting point.

Q. What is the cost of the Wildfire Risk Distribution Mitigation Project?

A. The current capital costs requested in this case for 2025 are $289,368 for FP-325636 as shown on Statement B, Schedule B-2, page 2. Upon approval of the RSIR, the Company would file the rider as explained further in the testimony of Mr. Bradley Davison. The currently forecasted costs for 2026 and 2027 are:

	2026	2027
FP-325636	$ 936,012	$935,992

These annual capital costs for the undergrounding or hardening of the existing overhead distribution lines for reduced fire risk are based on the approved budget dollars within the given year. The estimated costs for this project are expected to be approximately $8.5 million in today's dollars. It is estimated that approximately half of the 138 miles of existing overhead distribution lines would be converted to underground, and the other half would be brought up to current improved equipment and overhead distribution engineering standards.

Q. How will Montana-Dakota customers benefit from this project?

A. The project is designed to minimize the risk of the electric distribution system initiating a fire event. By minimizing this wildfire risk, the project directly improves the overall safety to the public and the safety to Montana-Dakota employees. There is direct improvement in system

reliability from the mitigation efforts reducing the likelihood of faults occurring on the distribution system. Additionally, there is an increase in avian and other animal, safety around the distribution structures as a result of the undergrounding and overhead distribution structure mitigation improvements that include new insulated materials and improved avian voltage spacing on remaining overhead structures and equipment.

Q. The project completion date is beyond 2025, why is this included?

A. Montana-Dakota will include this project within its proposed RSIR.

Q. Why is Montana-Dakota proposing the RSIR?

A. Montana-Dakota proposes to include this project within its RSIR. This rider mechanism will allow reliability and risk reduction projects which provide safety and reliability benefits for customers, but are not supported by incremental customer load, to be planned and executed by Montana-Dakota with the certainty of timely recovery.

Allowing the use of the rider mechanism will more gradually increase rates and step customers through cost increases in a more manageable transition. Finally, the use of a rider will decrease the expense associated with filing more frequent rate cases. The rider is discussed in more detail in the testimony of Mr. Bradley J. Davison.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Wyoming

Docket No. 20004-__-ER-25

Direct Testimony

Of

Robert Frank

Q. Please state your name and business address.

A. My name is Robert Frank, and my business address is 400 North Fourth Street, Bismarck, North Dakota.

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

A. I am employed by Montana-Dakota Utilities Co. (Montana-Dakota) as the Director of Electric Transmission Engineering.

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

A. I have leadership responsibility for the engineering, design, construction, and maintenance of Montana-Dakota's electric transmission and substation facilities, including property and right-of-way acquisitions of the Company.

Q. Please outline your educational and professional background.

A. I received my Bachelor of Science degree in Electrical Engineering from North Dakota State University in 2002. I received my Master of Business Administration from the University of Mary in 2008. In 2015, I

attended the Utility Executive Course at the University of Idaho. I am a registered Professional Engineer in the State of North Dakota.

I began my career at Montana-Dakota in 2004 as a system protection engineer in the Electric Transmission Engineering Department. Throughout the next ten years, I worked on various substation and transmission projects gaining experience in engineering design, project management, construction management, and real estate transactions. In 2014, I accepted my current position.

Prior to joining Montana-Dakota, I worked for an industrial contractor as a field engineer providing engineering support to construction crews and performing project management duties.

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

A. Yes. I have previously presented testimony before the Public Service Commissions of North Dakota and Montana and the Public Utilities Commission of South Dakota.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Montana-Dakota's Sheridan to Big Horn 41.6 kV line that is planned for 2025 and included in this case. I will also provide information regarding Montana-Dakota's proposed Reliability and Safety Infrastructure Rider Tariff Rate 55 (RSIR). More specifically, I will provide an explanation for one of the projects related to the proposed RSIR, the benefits provided by the projects, and the estimated costs expected to relate to the RSIR proposal.

Q. What projects are planned to be associated with the proposed RSIR?

A. There are three multi-year projects that are to be included in the Company's Electric Distribution System (EDS) in the Wyoming service territory:

1. An Underground Vintage Cable Replacement Program;
2. Wildfire Risk Electric Distribution Mitigation Program; and
3. Sheridan to Dayton 41.6 kV line.

The overall goal of these projects is to increase service reliability and safety for customers and employees in Montana-Dakota's service territory. I am responsible for the Sheridan to Dayton 41.6 kV line. The Underground Vintage Cable Replacement Program and the Wildfire Risk Electric Distribution Mitigation Program are covered in the testimony of Mr. Daryl Anderson.

Transmission Line Construction – Sheridan Southwest to Big Horn 41.6 kV Line

Q. Please describe the Sheridan Southwest to Big Horn Line project.

A. This project would create a 41.6 kilovolt (kV) transmission line loop between the Sheridan Southwest Transmission Substation in Sheridan and the Big Horn Distribution Substation in Big Horn. Customers of Big Horn and other customers south of Big Horn are currently served from a radial 41.6 kV line tapped on the Sheridan Southwest to Sheridan 41.6 kV transmission line. This loop line will provide redundancy for our southern

system and improve reliability. This new line will be approximately 4.25 miles long.

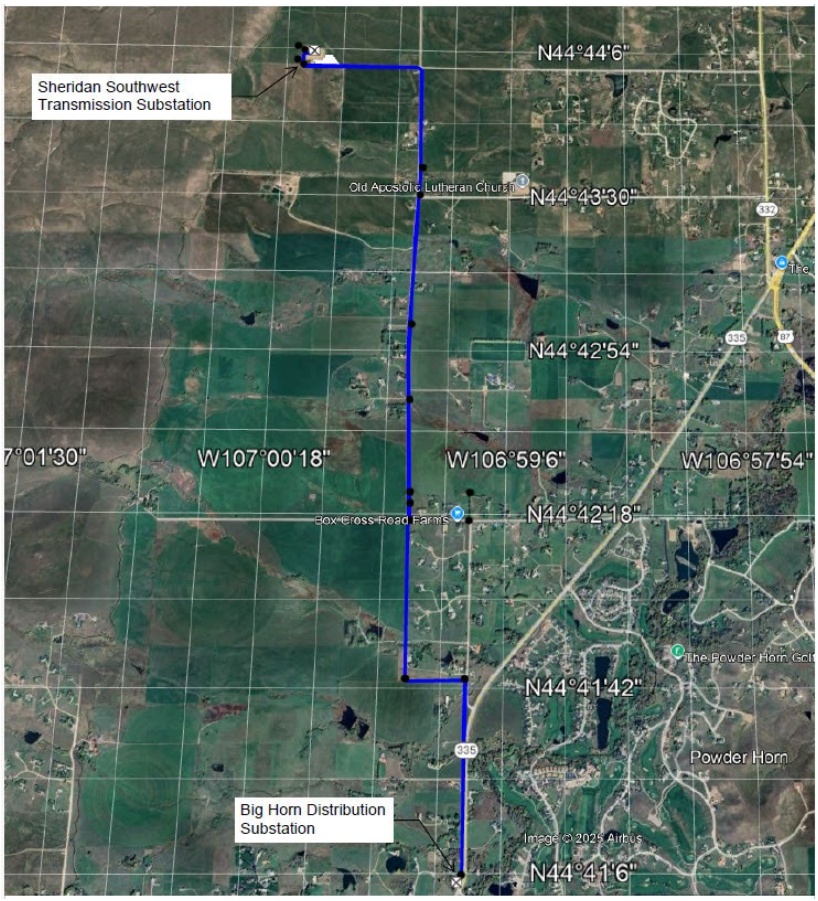


Figure 1 – Sheridan SW to Big Horn Line Route

Q. Why did Montana-Dakota undertake this project?

A. A radial line produces significant reliability challenges during normal system operations and emergency or storm operations. A significant outage to a radial line can result in extended outages. A transmission loop allows for removing sections of the existing lines for maintenance, repair, or replacement.

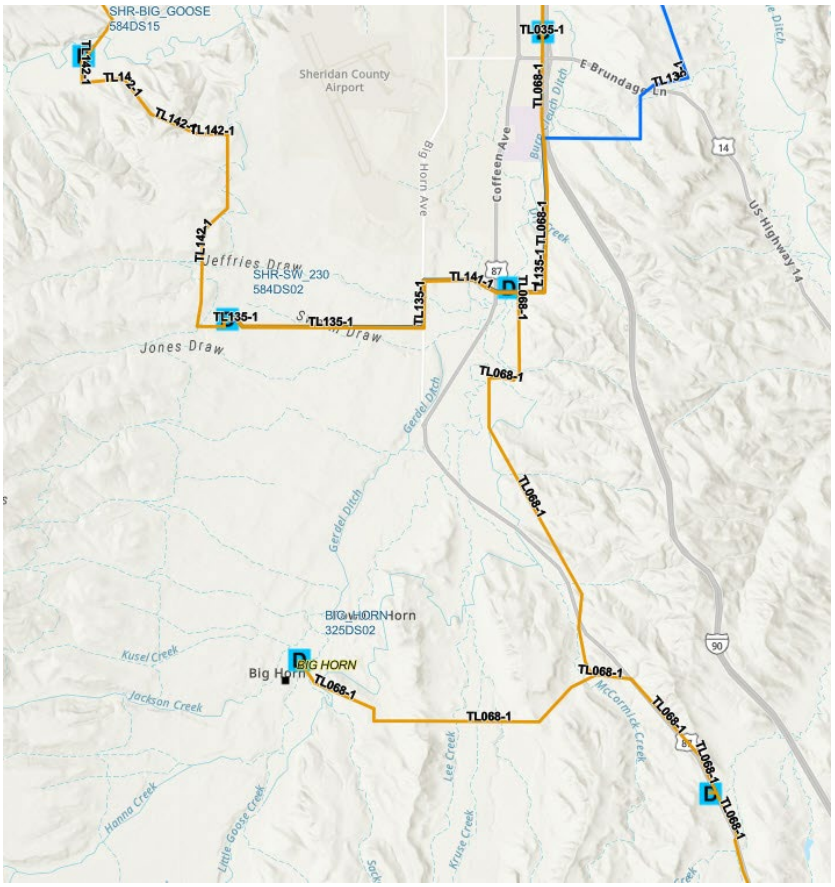


Figure 2 – Sheridan SW to Big Horn Existing Transmission

Q. What is the project timeline?

A. We are currently working on right-of-way acquisition, design, and engineering with an anticipated construction start of late summer of 2025 and completion by the end of the year.

Q. How will Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers will see improvement in reliability from a looped transmission system. Reliability can be improved by having operational flexibility for switching operations or storm restoration. New transmission lines are designed using updated engineering standards and constructed using modern materials and equipment. In addition to

improving reliability, the transmission lines are designed to help reduce wildfire risk and avian incidents.

Q. Describe alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. No alternatives exist if the goal is to improve reliability and operational flexibility by creating a looped transmission system.

Q. What are the costs of the project?

A. The current capital costs requested in this case for 2025 are $3,014,600 for FP-316136 as shown on Statement B, Schedule B-2, page 2.

<u>Transmission Line Construction – Sheridan to Dayton 41.6 kV Line</u>

Q. Please describe the Sheridan to Dayton Line project.

A. This project would create a 41.6 kilovolt (kV) transmission line loop between the Sheridan Southwest Transmission Substation in Sheridan and the Dayton Distribution Substation in Dayton. Customers of Dayton, Ranchester, and other customers west of Sheridan are currently served from a radial 41.6 kV line connected to the Sheridan Transmission Substation, approximately 24 miles away. This loop line will provide redundancy for our northwestern system and improve reliability. This new line will be approximately 20 miles long.

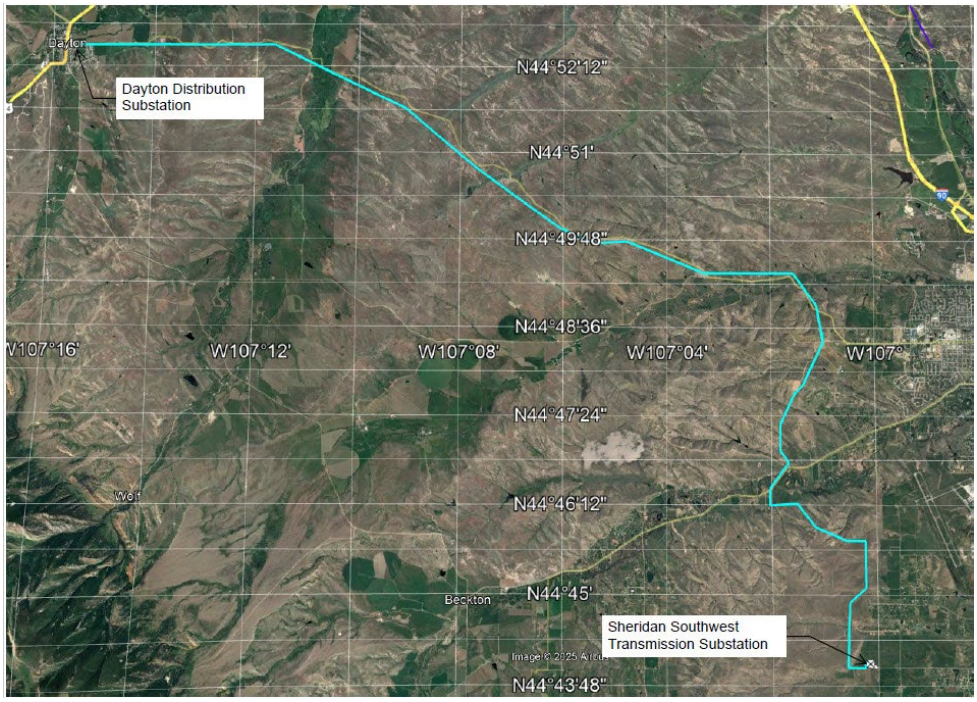


Figure 3 – Sheridan SW to Dayton Line Route

Q. Why will Montana-Dakota undertake this project?

A. A radial line produces significant reliability challenges during normal system operations and emergency or storm operations. A significant outage to a radial line can result in extended outages. A transmission loop allows for removing sections of the existing lines for maintenance, repair, or replacement.

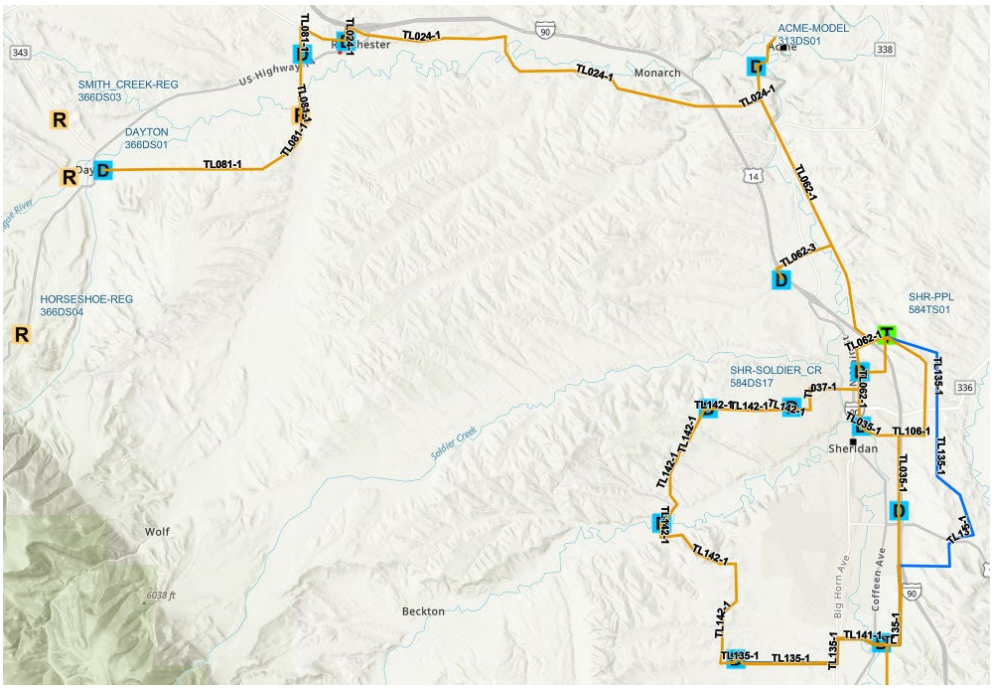


Figure 4 – Sheridan to Dayton Existing Transmission

Q. What is the project timeline?

A. We are currently working on right-of-way acquisition, design, and engineering with an anticipated construction start of late summer of 2026 and completion in late 2027.

Q. How will Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers will see improvement in reliability from a looped transmission system. Reliability can be improved by having operational flexibility for switching operations or storm restoration. New transmission lines are designed using updated engineering standards and constructed using modern materials and equipment. In addition to improving reliability, the transmission lines are designed to help reduce wildfire risk and avian incidents.

Q. Describe alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. No alternative exists if the goal is to improve reliability and operational flexibility by creating a looped transmission system.

Q. What are the costs of the project?

A. The estimated cost to construct this new transmission line is $8,417,442 and is shown as FP-316135 in Exhibit No.___(BJD-1).

Q. The project completion date is beyond 2025, why is this project a topic of discussion for this case?

A. Montana-Dakota proposes to include this project within its RSIR. This rider mechanism will allow reliability and wildfire risk mitigation projects which provide safety and reliability benefits for customers, but are not supported by incremental customer load, to be planned and executed by Montana-Dakota with the certainty of timely recovery.

Allowing the use of a rider mechanism will more gradually increase rates and step customers through cost increases in a more manageable transition. Finally, the use of a rider will decrease the expense associated with filing more frequent rate cases. This rider is discussed in more detail in the testimony of Mr. Bradley J. Davison.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Wyoming Public Service Commission

Docket No. 20004-___-ER-25

Testimony

Of

Joseph E. Geiger

Q. Please state your name and business address.

A. My name is Joseph E. Geiger 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 Director of Generation in the power production department of Montana-Dakota Utilities Co. ("Montana-Dakota").

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

A. I have overall responsibility for the day-to-day operation of Montana-Dakota's electric generation facilities, represent Montana-Dakota's interests in jointly owned generation facilities operated by other companies, and I am also responsible for new generation development.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Electrical Engineering from the University of North Dakota. My work experience includes six years of experience as a plant engineer, nine years of experience in varying roles of plant supervision/management, and five years of generation

development and operational responsibilities in my current position which includes coal-fired, gas-fired, and renewable generation.

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

A. Yes, I have testified before the Montana and North Dakota Public Service Commissions, and South Dakota Public Utilities Commission.

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

A. The purpose of my testimony is to provide a description, schedule and cost estimate for the WYGEN III project work included in this case.

Q. Please describe the WYGEN III facility.

A. The WYGEN III facility is a net 100 MW coal-fired generating facility located outside of Gillette, Wyoming. It is operated by Black Hills Energy and Montana-Dakota has a twenty-five percent ownership share of the facility. WYGEN III is adjacent to the Wyodak mine, which provides fuel for the facility.

Q. Please describe the schedule for the WYGEN III project work.

A. The majority of the project work is taking place in 2025 during a major overhaul that was originally planned for 2027. The project work was accelerated and moved into 2025 to take advantage of the downtime that was required to repair the generator stator ground after an unexpected failure which occurred on February 14, 2025. All of the funding projects referenced below are anticipated to be placed in service and used and useful in 2025.

Scheduled maintenance is required to ensure continued operation of the facility. A large portion of scheduled maintenance activities occur during downtime, or outages, that allow for access to systems or equipment required for operation.

Q. Please provide a description of the WYGEN III project work including pro forma cost breakdown.

The pro forma cost of the WYGEN III project work is $2,773,403 as shown in Statement B, Schedule B-2, page 2 with the breakout below.

- FP-100762 Minor Construction Project $260,904
  - This funding project covers several lower cost projects including mechanical repairs, environmental monitoring system maintenance, safety related improvements, and electrical/controls maintenance.
- FP-319905 Replace Baghouse Bags $121,819
  - Baghouse bag procurement and replacement required due to build up of particulate matter from normal operation. The baghouse is equipment utilized to control particulate matter for environmental regulations.
- FP-322976 Boiler Repairs $258,821
  - Boiler superheater, waterwall, and other steam/water tube inspections and repairs required due to normal degradation in the boiler.

- FP-325802 Replace Selective Catalytic Reduction (SCR) Catalyst $95,180
    - Routine SCR catalyst replacement required due to build up from normal operation. The SCR is equipment utilized to control NOx for environmental regulations.
- FP-326393 Generator Stator Rewind $1,290,768
    - A phase-to-phase ground was found in the generator stator requiring a rewind. A stator rewind is the process of replacing damaged coils inside a generator's stator in order to allow the unit to resume generating electricity. The stator rewind required replacement of copper bars and additional supporting materials. The stator ground was determined to be the cause of the extended outage.
- FP-326512 Aux Cooler – 4 Modules Replacement $74,948
    - Air compressor, turbine, generator cooling system module replacement required due to damage from freezing during downtime from generator ground incident.
- FP-326513 Aux Cooler – 1 Module Replacement $37,235
    - Air compressor, turbine, generator cooling system module replacement required due to damage from

freezing during cold weather months not related to generator ground incident.

- FP-326511 Aux Cooler Temperature Sensors $26,291
  - Temperature sensors added to provide more indication prior to freeze events.
- FP-326514 Isophase Insulator Replacement $54,319
  - Found damaged insulators during routine major outage inspections that needed replacement.
- FP-325800 Turbine Major Overhaul $352,286
  - Inspection of steam turbine found damage to first stage blading and a single blade on the last stage of the steam turbine requiring replacement.
- FP-318670 Wygen III Controls Upgrade $200,832
  - Periodic manufacturer updates to the plant and turbine controls systems including power supply and controls card upgrades needed to complete the project.

Q. Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

DOCKET NO. 20004-___-ER-25

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 28 Quarry Park Blvd SE, Suite 350, Calgary, Alberta, T2C 5P9.

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 Wyoming Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

Q5. Please describe your education and experience.

A5. I am a Certified Depreciation Professional, with 45 years of regulatory plant accounting and depreciation experience, and 25 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), Schedule 1.

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 plant in service of the Montana-Dakota – Electric Division ("MDU" or the "Company"), as of December 31, 2020. My detailed report, including my analyses and recommendations, is provided in Exhibit No. LEK-3, titled "Calculated Annual Depreciation Rates Applicable to Plant in Service as of December 31, 2020". Exhibit No. LEK-4 represents the depreciation tables. The detailed depreciation study report was prepared by me or under my direction**.** In addition, my Direct Testimony is to set forth the results of my full and comprehensive depreciation study of the plant for Montana-Dakota Common assets. My detailed report, including my analyses and recommendations, is provided in Exhibit No. (LEK-5), titled "Calculated Annual Depreciation Rates Applicable to Common Plant in Service as of December 31, 2021".

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. In addition, as the study was completed over the period in which COVID protocols were in place, I relied on my notes from my operational site tours from the 2018 Depreciation Study completed by Concentric. The

completion of the 2018 depreciation study included tours of three Company substations and switch yards, a coal fired thermal generation plant, gas turbine generation facility, the Company service building and yard, and the MDU electric control room. Lastly, I also reviewed the average service life and net salvage indications of many North American based electric utilities to test the results of my analysis against the electric 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, with a particular focus on the impact of the WYGEN III unit and associated facilities in Wyoming. 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 electric generation, transmission, distribution, and general plant assets of the MDU Electric Division, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of investment, as of December 31, 2020. 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 electric assets in service, as of December 31, 2020.

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, 2017, was available to be incorporated into our database. Additional reliable aged data, for the period January 1, 2018 through to December 31, 2020, was provided by the Company and incorporated into 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 electric system industry, including knowledge of service life estimates used for other electric 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 $56.8 million, when applied to depreciable plant balances, as of December 31, 2020. 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	
Steam Plant	$372,470,891	2.45%	$9,115,697
Other Production Plant	$537,757,981	3.98%	$21,377,839
Transmission Plant	$522,283,617	1.70%	$8,889,889
Distribution Plant	$461,078,839	3.25%	$15,005,624
General Plant	$33,261,966	7.34%	$2,443,013
Total Plant in Service	$1,926,853,295	2.95%	$56,832,062

Q15. How do the above depreciation rates compare to the currently approved depreciation rates?

A15. The following chart summarizes the proposed composite depreciation rates as compared to the currently applied for composite depreciation rates.

Plant Group	Proposed Depreciation Rate	Currently Applied Depreciation Rate
Steam Plant	2.45%	2.69%
Transmission Plant	1.70%	4.01%
Distribution Plant	3.25%	3.67%
General Plant	7.34%	1.33%
Total Plant in Service	2.95%	3.22%

Q16. Please describe the reasons for the change in the depreciation rates related to electric production plant.

A16. The largest influence in electric production depreciation rates results from the continued use of a Life Span approach applied to each generation unit. The impact of using the Life Span approach has been more dramatic in recent years because of the large capital spending primarily related to environmental requirements at several of the units.

Relative to specific Wyoming assets, the Life Span associated with WYGEN III unit did not change and thus the change in the depreciation rates was driven by investment in the plant being depreciated over the same 2060 Life Span date, albeit with the same or longer average service life recommendations, and a higher composite remaining life in the accounts associated with the WYGEN III Generation facilities.

Generation Station	Proposed	Currently Used
WYGEN III Generating Station	2060	2060

Q17. Please outline the reasons for the change in the composite depreciation rate for electric transmission.

A17. Within the electric transmission group of assets, extensions to the average service life estimates have a decreasing impact on the transmission system depreciation rates. The influence of the life selections overshadows the salvage, which also drives the decrease in the rates.

Q18. Please provide a summary of the current and proposed average service life estimates for transmission plant.

A18. 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 all but two accounts.

Account	Description	Proposed Iowa Curves	Current Iowa Curves
350.20	Land Rights	70-R4	50-R3
352.00	Structures and Improvements	50-R2	45-R2
353.00	Station Equipment	65-R2.5	60-R3
354.00	Towers and Fixtures	60-R4	55-R5
355.00	Poles and Fixtures	63-R2.5	50-R3
356.00	Overhead Conductors and Devices	70-R3	65-R3
357.00	Underground Conduit	50-R3	50-R3
358.00	Underground Conductors and Devices	50-R3	50-R3

The specific reasons for the average service life extensions for each of the large transmission accounts are discussed in Section 3.6 of my report. Additionally, the results of the statistical mortality study are presented for each account in Section 6 of my report. With regard to the Transmission assets in Wyoming, virtually all of

the investment is in the 353 – Station Equipment account relating to the WYGEN assets.

Q19. Is the average service life extensions, as noted above, typical for electric transmission assets?

A19. Yes. In a number of recent depreciation studies that I have completed, I have noted that the average service life of electric transmission 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 transmission infrastructure. For example, in recent years electric transmission utilities have been pro-active in pole and tower structure management and adding enhanced protection and control equipment within the substations. The specific life expectation of the digital protection and control systems is shorter than the previous electro-mechanical protection and control system, however, the enhanced protection provided within the substation of the new technology has had a life extension influence for transforming and switching equipment.

Q20. Please provide a summary of the current and proposed net salvage percentages for transmission plant.

A20. The following is a summary of the proposed net salvage percentages used in the depreciation rate calculations. I note that the currently approved 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. However, the following also provides a comparison of the recommended net salvage depreciation rate to the currently approved net salvage depreciation rate.

Account	Description	Proposed		Last Depn Study (*)	
		Net Salvage %	Depn Rate	Net Salvage %	Depn Rate
350.20	Land Rights	0	0.00%	0.00	0.00%
352.00	Structures and Improvements	0	0.03%	0.00	-2.03%
353.00	Station Equipment	-10	0.10%	-10	0.15%
354.00	Towers and Fixtures	-20	0.77%	-5	0.15%
355.00	Poles and Fixtures	-35	0.59%	-50	1.18% 0.60%
356.00	Overhead Conductors and Devices	-20	0.46%	-15	0.51%
357.00	Underground Conduit	0	0.00%	0.0	0.00%
358.00	Underground Conductors and Devices	0	0.19%	0.0	0.00%

(*)Rate identified in yellow represents the depreciation rate after negotiated settlement.

The specific reasons for the net salvage percentages for each of the large transmission accounts are discussed in Section 3.6 of my report. Additionally, the results of the statistical net salvage study are presented for each account, in Section 7 of my report.

Q21. Please outline the reasons for the increased composite depreciation rate for the electric distribution assets.

A21. The average service life estimates for the electric distribution assets have extended in a similar fashion as described for the average service life extensions of the

electric transmission assets. However, in the circumstances of the distribution assets, the need for more negative net salvage percentages has had a depreciation rate increase impact that out-weighed the influence of a decrease due to the life extensions. 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 all but four accounts.

Account	Description	Proposed Iowa Curves	Current Iowa Curves
360.2	Rights of Way	62-R3	50-R2
362.00	Station Equipment	53-R2	50-R2.5
364.00	Poles, Towers & Fixtures	60-R1.5	50-R1
365.00	Overhead Conductor & Devices	65-R2	55-R1
366.00	Underground Conduit	50-R3	50-R3
367.00	Underground Conductors and Devices	42-R2.5	40-R2
368.00	Line Transformers	55-R3	55-R3
369.10	Services	50-R3	45-R3 (*)
370.00	Meters	20-L3	20-L3
371.00	Installation on Customer Premises	20-R0.5	22-R0.5
373.00	Street Lighting System	43-R1	43-R1

(*) For comparison purposes, the underground Iowa curve has been used as it accounts for the majority of the investment. The current study proposes to aggregate the overhead and underground into one depreciation rate.

The specific reasons for the average service life extensions for each of the large distribution accounts are discussed in Section 3.6 of my report. Additionally, the results of the statistical mortality study are presented for each account, in Section 6 of my report.

Q22. Are the average service life extensions, as noted above, typical for electric distribution assets?

A22. Yes. In a number of recent depreciation studies that I have completed, I have noted that the average service life of electric 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 electric distribution utilities have been pro-active in pole structure management and adding enhanced protection and control equipment within the substations. The specific life expectation of the digital protection and control systems is shorter than the previous electro-mechanical protection and control system, however, the enhanced protection provided within the substation of the new technology has had a life extension influence for transforming and switching equipment.

Likewise, I have noted that the life of distribution line assets has also benefited from enhanced technology and the pro-active maintenance programs undertaken by electric distribution utilities. The introduction of pole testing and treatments for wood structures have provided electric distribution utilities with the ability to recognize longer lives. As such, the average service life extensions as observed in this study are consistent with my observations in a number of other electric utilities.

Q23. Please provide a summary of the current and proposed net salvage percentages for distribution plant.

A23. 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. However, a comparison of the recommended net salvage depreciation rates to the currently approved net salvage depreciation rate is also provided.

Account	Description	Proposed		Last Depn Study (*)	
		Net Salvage %	Depn Rate	Net Salvage %	Depn Rate
360.20	Rights of Ways	0%	0.00%	0%	0.00%
362.00	Station Equipment	(15)%	0.27%	(5)%	0.13%
364.00	Poles, Towers & Fixtures	(120)%	2.50%	(100)%	2.17% 1.50%
365.00	Overhead Conductor & Devices	(110)%	1.98%	(95)%	1.62% 1.26%
366.00	Underground Conduit	0%	-.06%	0%	-0.05%
367.00	Underground Conductor & Devices	(50)%	1.84%	(25)%	0.73% 0.33%
368.00	Line Transformers	(20)%	0.58%	(25)%	0.50% 0.25%
369.10	Services	(50)%	0.84%	(55)%	0.94% 0.23%
370.00	Meters	(5)%	0.57%	(5)%	0.46%
371.00	Installation on Customers Premises	(15)%	1.93%	(35)%	1.51%
373.00	Street Lighting System	(45)%	1.16%	(55)%	0.97%

(*)Rates identified in yellow represent the depreciation rate after negotiated settlement.

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. Five of the nine distribution accounts that had proposed cost of removal recovery in the 2015 study, now indicate the need for increased levels from the level witnessed in the 2015 study. Given the period from 2015 through 2020 has incorporated a lower than recommended rate for a number of the Depreciation accounts, this current depreciation study is proposing a significant increase in the depreciation for the company's distribution assets.

The detailed analysis of the net salvage estimates is provided in Section 7 of my MDU report.

Q24. Is the trend for more negative net salvage percentage, as noted above, typical for electric distribution assets?

A24. 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 2018 Society of Depreciation Professionals conference held in September, 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.

Q25. What is causing this trend to increased cost of removal of utility assets?

A25. 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. For example, in the MDU Account 364 – Distribution Poles and Fixtures, the average service life has been extended in this study from 50 years to 60 years. Also, the last depreciation study increased the average life from 38 years to 50 years for this same account. As such, over the course of two depreciation studies, the indications of average service life have increased from 38 years to 60 years (a 58% increase). As the average service life has increased, the length of time between the original installation of the assets in this account and the estimated average time of retirement of the asset is 58% 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 58% increase in the life expectation, also results in an increased length of time that the labor associated with the removal is 58% longer. When it is considered that in this account, the impacts of inflation of an additional 22 years are recognized in the cost of removal included in my study as compared to the study completed two studies ago, and an additional 10 years when compared to the last depreciation study, it is expected and reasonable to see the increases in cost of removal. To the extent that the average service lives for distribution assets have extended, the impact as

described above (for Account 364) applies to a number of the MDU electric 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 asbestos and PCB contaminants at substations 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.

Q26. Please summarize your proposed average service life estimates for the general plant assets as compared to the currently approved average service life for the general plant assets.

A26. The average service life estimates for the general plant assets have generally remained consistent with the currently approved average service life estimates with the exception of three accounts. The following is a summary of the proposed average service life estimates compared to the currently approved estimates,

Account	Description	Proposed Iowa Curves	Current Iowa Curves
390.00	Structures and Improvements	30-L0.5	29-L2
391.10	Office Furniture and Equipment	15-SQ	15-R1.5
391.30	Computer Equipment - PC	5-SQ	5-R3
391.40	Computer Equipment - Prime	5-SQ	5-SQ
391.50	Computer Equipment - Other	10-SQ	10-L3
392.10	Transportation Equipment - Trailers	25-R4	15-R4
392.20	Transportation Equipment	11-L3	11-L3
393.00	Stores Equipment	30-SQ	30-R2
394.00	Tools, Shop & Garage Equipment	20-SQ	20-R2
395.00	Laboratory Equipment	20-SQ	20-R3
396.10	Work Equipment - Trailers	25-L3	20-L3
396.20	Power Operated Equipment	9-L0	9-L0
397.10	Radio Communication Equipment - Fixed	15-SQ	15-R3
397.20	Radio Communication Equipment - Mobile	15-SQ	15-R3
397.30	General Telephone Communications Equipment	10-SQ	10-R3

Account	Description	Proposed Iowa Curves	Current Iowa Curves
397.50	Supervisory & Telemetering Equipment	10-SQ	10-R1.5
397.60	SCADA System	10-SQ	10-R3
397.80	Network Equipment	5-SQ	5-R3
398.00	Miscellaneous Equipment	25-SQ	25-R3

Q27: Was a Common Asset depreciation study also completed?

A27. 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-5, titled "Calculated Annual Depreciation Rates Applicable to Common Plant in Service as of December 31, 2021".

Q28: Please provide a summary of the results of the Common depreciation study.

A28. 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

II. DEPRECIATION METHODS AND PROCEDURES

Q29: How is depreciation defined for a rate regulated utility?

A29. Depreciation defined – "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric 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, wind storms, 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

[1] Federal Energy Regulatory Commission, Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Definitions

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 depreciation, which was adopted for use in my study.

Q30. Please outline the depreciation methods and procedures used in your depreciation study.

A30. 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.

A detailed account by account analysis of the factors considered in the selection of my recommended average service life estimates is provided in Section 3.6 of my depreciation study report.

Q31. Please outline any changes that you made in the depreciation method, grouping procedures or remaining life calculations as compared to previous depreciation studies.

A31. 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 was 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, 2020), 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, 2020.

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.

III. CONCLUDING REMARKS

Q32. What is your conclusion with respect to Montana-Dakota's proposed Depreciation expense?

A32. My conclusion is that Montana-Dakota's requested depreciation rates, for the Wyoming assets resulting in a composite depreciation rate, for the common and electric studies, of 3.16%, 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 study, that I prepared for this proceeding, be adopted by the Commission for regulatory purposes as well as by the Company for financial reporting purposes.

Q33. Does this conclude your Direct Testimony?

A33. Yes, it does.

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

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
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
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
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
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
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
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
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
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
2018	FortisBC Energy Inc.	FortisBC Energy Inc.	British Columbia Utilities Commission	N/A
2018	FortisBC Inc.	FortisBC Inc.	British Columbia Utilities Commission	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
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 Wyoming

Docket No. 20004-___-ER-25

Direct Testimony

Of

Tara R. Vesey

Q. 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. Please describe your duties as Regulatory Affairs Manager.

A. I am responsible for the overall management of the general rate case filing process for each of the jurisdictions in which Montana-Dakota operates, including the preparation of gas and electric cost of service studies and the associated pro forma operating income, rate base, and rate of return, and the additional revenue requirement for each distinct jurisdiction.

Q. 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 Montana 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 Wyoming electric operations per books cost of service for the twelve months ended December 31, 2024 and the pro forma cost of service reflecting known and measurable adjustments that will occur by December 31, 2025. Based on the results, I have prepared the calculation of the revenue deficiency. I will also discuss the Company's proposal to include the pension and benefits regulatory asset and the post retirement benefits regulatory asset. I will provide background on the Power Supply Cost Adjustment, including an explanation of the calculations included in the

application. Finally, I will introduce the proposed Reliability and Safety Infrastructure Rider Rate 55 Tariff (RSIR).

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

A. I am sponsoring Statements A through D and F through J, Statement M, and the revenue requirement presented in Exhibit No.___(TRV-1). Finally, I am sponsoring the proposed Power Supply Cost Adjustment Rate 50 presented in Exhibit No.___(TRV-2).

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

A. Yes, they were.

<u>Case Description</u>

Q. What is the revenue deficiency?

A. The Company has determined a revenue shortfall of $7,507,709, which represents a 24.4 percent increase from current rates, based on a pro forma 2025.

Q. How was the $7,507,709 revenue deficiency derived?

A. 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, 2024 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 Wyoming electric operations for the twelve months ended December 31, 2024?

A. Statement A, pages 2 and 4 show the per books income statement and rate base for Wyoming. As shown on page 2, Wyoming electric operations had a return on rate base of 4.160 percent for the twelve months ended December 31, 2024. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the applicable Statement listed. Pages 3 and 5 list the pro forma adjustments to operating revenues, expenses and rate base. All adjustments were calculated on either a Wyoming specific basis or on a total Company basis and allocated to Wyoming, as indicated on the statement or schedule detailing each adjustment.

Q. How was the per books cost of service allocated to Wyoming?

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. The Company's Cost Allocation Manual details the method of assigning costs to the Wyoming gas operations and included in Statement M.

Q. Please explain the allocation method used for the Pro Forma period.

A. Traditionally, in Wyoming rate cases, Montana-Dakota has created a Corporate Allocation Operations and Maintenance Adjustment in order to harmonize the expenses with the three-factor allocation which was recommended by the Office of Consumer Advocate.

However, on June 1, 2023, Knife River Corporation completed its spinoff from MDU Resources Group, Inc., and on November 1, 2024, Everus Construction completed its spinoff from MDU Resources Group, Inc.

Because of the change in Company makeup to a pure play utility, the Company began using a three-factor allocation factor to allocate certain corporate charges in January 2025. The three factors considered are gross plant, gross revenues less cost of goods sold, and direct labor. As shown in statement M, page 18, the current three factor allocation for Montana-Dakota is 45.96 percent. The previously used allocation factor, based on average capitalization, as of December 2024 was 43.1 percent. Based on this analysis and the de minimis variance, the Company did not perform an adjustment.

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

A. The revenue requirement is based on December 31, 2024 test period to create a pro forma year ending December 31, 2025. As stated by Ms. Kivisto, the proposed $7.5 million increase in revenue since the

last case is largely driven by:

	Amount (in millions)
O&M Increase	$3.1
Rate Base	2.4
Depreciation	2.2
Change in ROE	0.9
Pension & Post Retirement	0.4
Other	0.3
Margin	(1.8)
Net Increase	$7.5

Montana-Dakota's cost of doing business in Wyoming is increasing despite the Company's effort to control costs and increase efficiency. The Company is experiencing a $3.1 million increase in O&M expenses due to increased WYGEN III costs, labor, insurance costs, subcontract labor, and software maintenance. Rate base investment since the last case, including the significant investments for the Big Horn to Sheridan Line covered in the testimony of Mr. Robert Frank and the WYGEN III major outage covered in the testimony of Mr. Joseph Geiger, represent $2.4 million of the increase. Increases in depreciation expense, primarily driven by the additional plant investment, and somewhat offset by the implementation of the updated depreciation studies supported in the testimony of Mr. Larry E. Kennedy, result in a revenue requirement increase of approximately $2.2 million. Finally, the proposed addition of the provision for pension and post retirement benefits, the proposed change in return on equity, and other items increase the revenue requirement by approximately $0.4 million, $0.9 million, and $0.3 million,

respectively. These increases are all offset by a change in margin, primarily driven by customer growth, that has reduced the revenue requirement by $1.8 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, 2025, conform with past Commission practices and are listed on pages 3 and 5 of Statement A. 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. Describe the pro forma adjustments to the income statement and rate base.

A. The adjustments to the income statement are summarized on Statement A, 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 Statement A, page 5 and include plant, accumulated reserve for depreciation and associated additions and deductions. Each adjustment is discussed in detail below.

Pro Forma Income Statement

Q. What adjustments were made to operating revenues?

A. The adjustments to operating revenues are contained in Statement F. Schedule F-1, Adjustment No. 1, reflects the pro forma sales revenues

and is an increase in revenue of $116,073. The Company applied the Basic Service Charges, Energy Charges, and Demand Charges applicable under each rate schedule, as first authorized in Docket No. 20004-117-ER-16 and later updated to reflect the impact of the Tax Cuts and Jobs Act of 2017 in Docket No. 20004-135-ER-18, to the pro forma customers, energy use, and demand to derive the revenues shown on Statement F, Schedule F-1, pages 2 through 18. The Fuel and Purchased Power rates used in revenues reflect the pro forma Fuel and Purchased Power rates discussed later.

Adjustment No. 2, presented in Schedule F-2, includes adjustments to other operating revenues. The pro forma adjustment increases revenue by $93,741 and consists of several adjustments as follows:

- Seasonal Reconnect Fee, Reconnect Fee for Non-payment, NSF Check Fees, Sale of Sundry Junk Material, Patronage Dividends, KVAR Penalty Revenue, Miscellaneous Revenue, and Joint Use Agreements were adjusted to reflect a three-year average;
- Energy Diversion was updated based on 2025 actuals through February;
- Rent from Property reflects annualized actual 2025 activity through March. However, the pro forma revenue associated with Pole Attachments was increased to reflect a charge that is partially offset be an increase in rent expense; and

- 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.

Q. What adjustments were made to O&M?

A. The adjustments to operation and maintenance expenses are contained in Statement G and are summarized in pages 1 through 4 and each adjustment is detailed in Statement G, Schedule G-1.

Q. Were fuel and purchased power costs updated?

A. Fuel and purchased power (Adjustment No. 3) is shown on Schedule G-1, page 3, and reflects a decrease of $48,099. This is based on the pro forma generation and power purchase requirements and has been updated to reflect pro forma cost assumptions and purchased power prices.

Montana-Dakota prepared this adjustment in the same manner as Docket No. 20004-117-ER-16. However, in 2016 Black Hills Energy changed its utilization of FERC 501.4 - Fuel Handling account to more appropriately include ash hauling costs, labor costs, outside services, site allocations, and payroll loading costs related to fuel handling. These costs are all in addition to the ash reclamation fees that were discussed to be included in the Power Supply Cost Adjustment Rate 50 (PSCA) as well as the fuel and power purchase requirements in the last case. To exercise an abundance of caution, Montana-Dakota committed to only including ash

reclamation fees in its annual PSCA filling until such time as the costs can be reviewed in a rate case.

The costs included in the Fuel Handling fall within the FERC guidelines and are directly related to coal and other fuel handling costs associated with the WYGEN III unit. Furthermore, they are all representative of variable costs associated with the utilization of WYGEN III. This would require no tariff change. The Company only wants to be fully transparent about its interpretation of the existing tariff language.

See the table below for the comparison of the costs included in the annual PSCA filing and the actual 501.4 balance as well as the average effect on the PSCA adjustment. It should be noted that absent recovery in the fuel and purchase power adjustment, an increase in the WYGEN III Adjustment No. 4 would be necessary.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Annual PSCA				$5,571	$6,673	$6,632	$4,316	$3,527	$1,334	$881	$573
Total 501.4 - Fuel Handling	$6,184	$7,487	$374,513	208,023	135,305	166,951	159,935	166,697	207,163	205,351	213,624
Variance	$6,184	$7,487	$374,513	$202,452	$128,632	$160,319	$155,619	$163,170	$205,829	$204,469	$213,051
kWh Sales				280,201,962	281,397,447	284,174,285	286,702,974	287,697,371	294,896,315	290,646,868	292,769,653
Effect on PSCA				$0.00072	$0.00046	$0.00056	$0.00054	$0.00057	$0.00070	$0.00070	$0.00073

Q. How was the WYGEN III Adjustment No. 4 determined?

A. The WYGEN III expense is shown as Adjustment No. 4, on Schedule G-1 page 4, and reflects a decrease of $147,350. The decrease is primarily due to Fuel Handling expense being included in the Cost of Fuel and Purchased Power, Adjustment No. 3, in the pro forma period which is offset by the pro forma cost of operation and a normalized outage schedule. The cost of operation and normalization process are more fully defined in Workpaper Statement G, pages 12 through 13.

Q. Would you describe the development of labor and benefits expense?

A. Yes. Labor expense is shown as Adjustment No. 5, in Statement G, Schedule G-1, page 5. The pro forma labor was developed by applying the percentage of total adjusted per books labor multiplied by the Pro forma labor by Object total. Pro forma total Company labor costs were based on the application of a weighted average increase of 4.55 percent for union employees and 3.5 percent for nonunion employees which is in effective 2025 as shown on Workpaper Statement G, page 14. Bonuses and commissions and meals reflect the actual stock compensation, expected miscellaneous expenses, and meals for 2024. Pro forma incentive compensation has been adjusted to reflect 11.31 percent of straight time, which is considered the incentive compensation target.

Finally, one full time line locator position was added to the Pro Forma period. The employee serves gas and electric customers and thus is allocated appropriately. This employee was hired in order to avoid increased subcontractor costs associated with line locating. Montana-Dakota has seen an increase in the number of line locate requests primarily from fiber optics companies. In order to comply with the State's One-Call requirements to locate lines within 2 business days of the request, a new employee was justified.

The labor expense pro forma adjustment results in an overall net increase of $108,919.

Benefits are shown on page 6 of Schedule G-1. Adjustment No. 6

is an overall increase in cost of $114,798. 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 11.94 percent to reflect the premiums in effect for 2025 as compared to the 2024 actual results. Actuarial Pension expense increased 296.87 percent and postretirement increased by 12.16 percent from 2024 levels. 401K expense increased 1.00 percent to reflect a change in policy effective January 1, 2025 which increased the Company's 401K match from 3.00 percent to 4.00 percent. 401K expense, workers compensation and other benefits are tied to labor costs and increase 4.19 percent to reflect the overall average increase in straight time labor.

Additionally, the benefits associated with the new line locator position referenced above were included. The calculation of these costs is shown on Workpaper Statement G, page 22.

Q. Would you describe the other adjustments made to O&M expense?

A. Yes. Vehicles and work equipment is shown as Adjustment No. 7, on page 7 of Schedule G-1 and 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. 7 reflects an increase of $77,471.

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 are used. The increase is primarily due to proposed depreciation rate change for Power Operated Equipment.

Uncollectible accounts, Adjustment No. 8, is a decrease of $19,424 based on the four-year average of net write-offs to revenues.

Postage expense, Adjustment No. 9, shown on page 9 of Schedule G-1, is an increase of $6,288 and reflects a 12.60 percent 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, 2024.

Adjustment No. 10 for advertising expense is shown on page 10 of Schedule G-1 and reflects a decrease of $8,577. Pursuant to past Commission policy, general promotional and institutional advertising expense has been eliminated. Informational advertising is adjusted to exclude advertising that is not applicable to Wyoming gas operations.

Insurance expense is shown on Adjustment No. 11 and reflects an increase of $77,034. This increase is adjusted to reflect actual 2025 expenses and a 5-year average of self-insurance expense. The increase is due to additional coverage and increases in limits necessary because of the risk associated with wildfires and the costs associated with covering the additional plant in service since the last case. Furthermore, Montana-

Dakota does plan to submit a wildfire mitigation plan later this year in compliance with Chapter 3, Section 401 of the Commission's Rules, which is effective July 1, 2025.

Materials expense shown as Adjustment No. 12, on page 12 is an increase of $7,164 and is adjusted to reflect an increase in transmission and distribution material expense due to anticipated increases associated with tariffs imposed in 2025.

Adjustment No. 13 shows Subcontract Labor expense in Schedule G-1, page 13 is based on the Pro Forma adjusted value to reflect an increase of $267,862. Non-reoccurring refunds were issued in 2024 which resulted in a lower-than-normal 2024 transmission expense. Additionally, an increase in audit fees are anticipated in the pro forma period.

Schedule G-1, page 14 is Adjustment No. 14 for software maintenance expense is an increase of $88,094 and is based on pro forma levels. This increase is driven by increases in license renewals and mandated security needs. Additionally, since 2016, Montana-Dakota has shifted to cloud based software licensing which has moved the expenses associated from capital to O&M.

Adjustment No. 15 for industry dues reflects the pro forma level of industry dues and is a decrease of $7,956. Statement G, Schedule G-1 page 15 shows those dues that are directly assigned or allocated to Wyoming, the appropriate pro forma expense level and the benefit to the

ratepayer. In recognition of the settlement in Docket No. 30013-415-GR-24, the Chambers of Commerce dues have been removed.

Regulatory commission expense shown as Adjustment No. 16 on page 16 of Schedule G-1 is an increase of $103,703. This adjustment reflects the expenses to be incurred in this filing amortized over a three-year period, the expenses related to depreciation studies amortized over a five-year period, and a three-year average of ongoing regulatory commission expenses. Montana-Dakota has proposed a three-year amortization period in this filing. While the Company has not filed a case for a longer period of time, and the Company is proposing the RSIR in this case, current capital projections indicate significant capital expenditures, not requested through the RSIR and are not supported by customer growth, will be required in the near future.

Rent Expense shown as Adjustment No. 17, on page 17 Schedule G-1, reflects the adjusted increase of $36,950. The projected 2025 reflects adjustments for increases in the WYGEN III station land lease and an increase in pole attachment expenses. The pole attachment expense is partially offset by revenue as shown on Statement F, Schedule F-2, page 1.

The items adjusted individually above represent approximately 98.4 percent of total Wyoming gas O&M. The remaining items, which make up approximately 1.6 percent of other O&M, are adjusted to reflect interest paid on customer deposits as approved in Docket No. 30013-351-GR-19

based on the 2024 Wyoming authorized interest rate. Additionally, an adjustment was made to eliminate aircraft expense that was not applicable to Wyoming electric operations. In recognition of the settlement in Docket No. 30013-415-GR-24, the aircraft expenses that were included, as well as those expenses excluded, in the All Other O&M are provided in detail on Workpaper Statement G, pages 52 through 54.

Q. Please describe the calculation of depreciation expense.

A. The adjustment to depreciation expense is contained in Statement H. Adjustment No. 19, as found on Schedule H-1, pages 1 through 4, restates the annual depreciation expense to the pro forma level of plant in service resulting in an increase of $1,500,632. Concentric Advisors, ULC prepared electric and common plant depreciation studies, at the Company's request. The electric study is based on plant in service as of December 31, 2020 and the common study is based on plant in service as of December 31, 2021. The depreciation studies are supported in the testimony of Mr. Larry E. Kennedy.

Q. Are there any changes to the calculation of depreciation expense?

A. Montana-Dakota has not historically included any expense related to the decommissioning of the WYGEN III unit. However, given the 2060 retirement date, the Company felt it was necessary to include some expense at this time. Montana-Dakota created a weighted average percent of the estimated decommissioning costs to plant in service for the Big Stone and Coyote Power Plants, as included in the South Dakota

Docket No. EL23-020, and amortized that expense over the remaining life of the WYGEN III unit. Montana-Dakota has not conducted a decommissioning study for WYGEN III; however, Big Stone and Coyote Power Plants have similarities that make them a good proxy for an estimated cost to begin recovery for future decommissioning activities. The Company expects to conduct a study in the future which it will use as a basis for future recovery.

This resulted in $101,461 in decommissioning expense per year that was included in the $1,500,632 of depreciation expense mentioned previously. The calculation of the decommissioning expense can be found on Statement Workpaper H, page 1.

Q. What adjustments were made to taxes other than income?

A. The adjustments to taxes other than income are contained in Statement I. Adjustment No. 20 restates ad valorem taxes to the pro forma level of plant in service based on the 2024 ratio of ad valorem taxes to plant. The net result is an increase of $23,723.

Adjustment No. 21 on page 2 of Statement I, Schedule I-1 shows payroll taxes reflecting an increase of $8,554 based on the ratio of payroll taxes to labor expense for 2024 applied to pro forma labor expense.

The Wyoming franchise taxes (Adjustment No. 22) is shown on page 3 of Schedule I-1 are restated to the pro forma revenue levels by applying the composite franchise rate to pro forma revenues for an increase of $1,979.

Adjustment No. 23 on page 4 of Schedule I-1, shows the Wyoming Uniform Assessment tax reflects pro forma based on 2024 assessment notice from the Department of Revenue. The net result in a decrease of $1,646.

Q. What adjustments were made to income taxes?

A. The adjustments to income taxes are contained in Statement J. The adjustment to current income tax (Adjustment No. 24) is shown on Schedule J-1, page 1 of Statement J. Current income tax expense also incorporates the adjustments to operating income for the change in interest expense and book/tax differences related to depreciation.

The adjustment to operating income to reflect the change in interest expense (Adjustment No. 25) is shown on Schedule J-1, page 2. Interest is deductible for tax purposes and interest expense is calculated based on the pro forma rate base using the weighted cost of debt and debt ratio from Statement E. The resulting interest expense is an increase of $411,531 from the per books level.

The closing/filing and prior period adjustments in the current income tax accrual and in the deferred taxes are eliminated on page 3 in Adjustment No. 26 and 27. Adjusted current and deferred income taxes match those calculated for Wyoming and conform to past Commission practices.

Pro Forma Rate Base

Q. How would you describe the development of the rate base?

A. Per books and pro forma rate base for Wyoming electric operations is summarized in Statement A, page 4. The pro forma rate base is based on the year end 2024 rate base and reflects known and measurable adjustments that will occur within twelve months of December 31, 2024. The pro forma adjustments to rate base are summarized on Statement A, page 5.

Statement B, page 1 summarizes the pro forma plant in service. Adjustment A, shown on Statement B, Schedule B-2, page 1, is the known and measurable plant additions that will be in service by December 31, 2025. The additions of $13,507,873 includes additions to steam production, transmission, distribution, general and common plant and is shown Statement B, Schedule B-2, pages 1 through 4.

Projects supporting incremental customers and associated volumes, often referred to as Growth Projects, have not been included in the Company's capital additions to plant as the level of customer additions consistent with past practice. Montana-Dakota acknowledges that as part of the settlement in Docket No. 30013-415-GR-24, the growth projects were included in rate base, along with the associated customers and revenue. However, given the phase of case preparation that Montana-Dakota was in, and because the Company has not typically normalized electric volumes in the pro forma period, it was not feasible to make that

electric volumes in the pro forma period, it was not feasible to make that change in this case.

Adjustment B, shown in Schedule B-3, pages 1 and 2, reflects Wyoming pro forma retirements which are primarily based on a three-year average and results in a reduction of $1,177,352.

Adjustment C, shown on Statement C, page 1, increases the reserve for depreciation on the per books plant by $6,024,570. This adjustment, combined with Adjustment B, restates the accumulated reserve to the pro forma level in order to match the pro forma plant levels. This results in a net increase of $4,847,218.

Q. How were the working capital items derived?

A. The working capital adjustments are summarized in Statement D. Detailed information for Adjustments D through K are shown on Schedule D-1, pages 1 through 8. Page 1 of Schedule D-1 shows materials and supplies balances restated to a thirteen-month average, with actual balances through March 2025, in Adjustment D, for a decrease of $15,465.

Prepaid Insurance is restated to a thirteen-month average in Adjustment E with actual balances through March 2025 and balances for April through December 2025 reflect pro forma expense as shown on Workpaper Statement D, page 1. It is expected to increase $29,904.

Unamortized loss on debt, Adjustment F, is shown on Schedule D-1, page 3, is being treated consistent with Docket No. 20004-117-ER-16.

It was calculated using the balance as of December 31, 2024 and Pro Forma 2025 resulting in a decrease of $32,902.

Adjustment G reflects unamortized redemption of preferred stock cost and was calculated using the balance as of December 31, 2024 and Pro Forma 2025, as shown on Statement D, Schedule D-1, page 4.

As discussed in detail below, proposed Adjustments H and I include the provision for pensions and benefits, and the provision for post retirement adjustments in the revenue requirement for the 2025. The associated accumulated deferred income taxes for pensions and benefits and post retirement were also included.

Customer Advances for Construction is calculated using the balance of December 31, 2024 and Pro Forma 2025 in Adjustment J, on Schedule D-1, page 7. Actual balances are reflected through March 2025 and balances for July through December 2025 reflect March 2025 balances. It is expected to decrease $261,540.

Adjustment K, shown on page 8 of Schedule D-1 is Wyoming Customer Deposits allocated to the electric utility based on annual sales revenue. Pro Form customer deposits are based on balances as of March 31, 2025.

Q. Montana-Dakota has proposed to include the net pension and post-retirement benefits regulatory assets in rate base. Will you explain why?

A. The Company's required contributions to the pension account

resulted in a significant prepaid asset and exceeded the amount of pension expense (commonly referred to as FAS 87 or ASC 715 expense) recovered through the revenue requirement. The contributions are tax deductible for Montana-Dakota and any earnings on those contributions in the pension trust account are not subject to income tax. With that in mind, the contributions help maintain the required funding level and, at the same time, typically result in lower FAS 87 expense.

Post retirement contributions are typically much more closely matched to the annual expense, so the prepaid asset is much smaller. However, Montana-Dakota considers the benefits and the circumstances surrounding the creation of both prepaid assets or liabilities that it is appropriate to include both pension and post retirement similarly.

The table below presents the pension and benefits regulatory asset or liability position for Montana-Dakota beginning in December 2004 through December 2024. As shown, Montana-Dakota has made cash contributions in the amount of $89.2 million but has recovered only $28.5 million through the inclusion of pension expense in the revenue requirement. Wyoming electric operations' share of the total Company pension regulatory asset is $1.9 million as of December 31, 2024.

MONTANA-DAKOTA UTILITIES CO.
PENSION BALANCE SUMMARY
ENDING DECEMBER 31, 2024

	Cash Contributions 1/	Pension Expense 2/	Pension Balance Debit (Credit)
Beginning Balance - 12/31/2004			$7,777,266
Activity - 2005	$0	$4,179,348	3,597,918
Activity - 2006	-	4,118,976	(521,058)
Activity - 2007	1,188,690	3,724,426	(3,056,794)
Activity - 2008	-	2,825,775	(5,882,569)
Activity - 2009	8,347,434	4,759,097	(2,294,232)
Activity - 2010	3,871,657	(5,328)	1,582,753
Activity - 2011	13,757,133	1,610,332	13,729,554
Activity - 2012	12,038,687	(740,118)	26,508,359
Activity - 2013	10,014,592	1,830,351	34,692,600
Activity - 2014	12,202,457	594,340	46,300,717
Activity - 2015	2,182,143	1,398,780	47,084,080
Activity - 2016	-	1,746,833	45,337,247
Activity - 2017	422,015	1,422,159	44,337,103
Activity - 2018	7,200,692	720,403	50,817,392
Corporate Reorg. Adj.	(5,133,171)	-	45,684,221
Activity - 2019	15,452,375	1,379,116	59,757,480
Activity - 2020		(177,300)	59,934,780
Activity - 2021		(727,718)	60,662,498
Activity - 2022		(814,687)	61,477,185
Activity - 2023	5,244,896	209,033	66,513,048
Activity - 2024	2,438,882	401,809	68,550,121
Total Funding	$89,228,482	$28,455,627	
Ending Balance - 12/31/2024			$ 68,550,121

1/ Actuarially determined cash payments to the pension trust fund.
2/ Actuarially determined pension expense use in the development of the revenue requirement through rate cases.

Q. Is Montana-Dakota required to make contributions to its pension trust fund? And what are the ramifications if funding is not maintained?

A. Yes. Internal Revenue Service rules govern minimum required pension funding contributions. If required contributions are missed or

delayed, the missed payment would be considered a reportable event under the Employee Retirement Income Security Act of 1974 (ERISA) rules. This could also subject the Company to excise taxes for failure to meet minimum funding requirements. In addition, if the funded status drops below certain levels, restrictions on benefit payments may be required as well as potentially increased premiums payable to the Pension Benefit Guaranty Corporation.

Q. Montana-Dakota has included pension and post-retirement benefits in this filing. Will you explain why the Company has decided to include these regulatory assets in rate base at this time?

A. As reflected in the table above, the pension regulatory asset has fluctuated from an asset to a liability and then, beginning in 2012, started to increase in magnitude as the Company had made significant funding contributions. However, the amount recovered through the revenue requirement (i.e. recovery of FAS 87 expense as a component of operating expenses) has decreased to the point that the regulatory asset has become a material asset upon which Montana-Dakota is not able to earn a return.

Q. Has the Company included pension and post-retirement benefits in other filings?

A. The Company has proposed pension and post-retirement benefits in Docket No. 30013-415-GR-24 without opposition.

Q. Would you describe the deductions to rate base?

A. The accumulated deferred income tax balances are summarized on Statement J, Schedule J-2, page 1. Adjustments M and O and Adjustment No. 28 shown on Schedule J-2, page 2, are associated with excess deferred income taxes resulting from changes in federal income tax rates.

Adjustment L and 29 are shown on page 3 of Schedule J-2. Adjustment L reflects the deferred income taxes on plant for pro forma plant additions. Adjustment No. 29 reflects net depreciation on plant in service 2025 tax depreciation. See Workpaper Statement J, page 1 and book depreciation see Statement Workpaper H, pages 4-6. Statement J, Schedule J-2, page 4 reflects the tax depreciation on plant additions.

Adjustment N, Decommissioning of Retired Power Plants shown on Schedule J-2, page 5 reflects the excess deferred income taxes associated with the amortization of the decommissioning of WYGEN III.

Q. Can you please explain Exhibit No.____(TRV-1)?

A. Exhibit No.____(TRV-1), which is identical to Statement A, page 1, shows the calculation of the revenue deficiency of $7,507,709 based on the pro forma operating income and rate base and using the overall rate of return of 7.985 percent from Statement E, page 1.

Reliability and Safety Infrastructure Rider

Q. Please describe the Reliability and Safety Infrastructure Rider Rate 55 (RSIR)?

A. The Company is proposing a Reliability and Safety Infrastructure

Rider which is intended to recover new or modified transmission level projects specific to the improvement of power delivery reliability to customers, replacement of pre-1985 underground distribution cables, and upgrades necessary for wildfire mitigation. The Company has identified three specific projects that the Company plans to include in future RSIR files. The projects are:

1. An Underground Vintage Cable Replacement Program discussed in detail in the testimony of Mr. Daryl Anderson;
2. A Wildfire Risk Electric Distribution Mitigation Program, also discussed in detail in the testimony of Mr. Daryl Anderson; and
3. The 41.6 kV Transmission Line Construction from Sheridan to Dayton, discussed in detail in the testimony of Mr. Robert Frank.

These projects provide safety and reliability benefits for customers but are not supported by incremental customer load. Investment in both Underground Vintage Cable Replacement and Wildfire Risk Electric Distribution Mitigation are expected to have continued investment for several years and transmission level projects, while less routine, are generally significant investments when they do occur. Because there is no incremental load tied to these projects, Montana-Dakota's opportunity to earn its return will be diminished and the capital investment associated with these projects will accelerate future general rate cases. Allowing the use of a rider mechanism will more gradually increase rates and step customers through cost increases in a more manageable transition.

Additionally, the use of a rider will decrease the expense associated with filing more frequent rate cases.

Q. How will the RSIR be calculated and included in rates?

A. The proposed RSIR provides a mechanism that allows the Company to proactively address wildfire mitigation, replace aging underground wires that are prone to failure, and improve power delivery reliability to customers while potentially delaying costly rate cases and providing customers with more gradual rate increases over time. As discussed above, the projects associated with the RSIR are covered in more detail in the testimony of Mr. Anderson and Mr. Frank.

The testimony of Mr. Bradley J. Davison will discuss the creation of the revenue requirement and provide an example of such a revenue requirement. The testimony of Ms. Stephanie Bosch will discuss the proposed tariff.

Power Supply Cost Adjustment Rate 50

Q. Is Montana-Dakota proposing to change the base cost of fuel and purchase power?

A. As shown in TRV-2, the base cost of fuel and purchase power is $0.03902 per kWh for primary service customers and $0.04422 per kWh for secondary service customers. The total cost of fuel and purchase power is $12,816,969.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA OPERATING INCOME AND RATE OF RETURN
ELECTRIC UTILITY - WYOMING
TWELVE MONTHS ENDED DECEMBER 31, 2024 WITH PRO FORMA ADJUSTMENTS
REFLECTING ADDITIONAL REVENUE REQUIREMENTS

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$30,818,550	**$7,507,709**	$38,326,259
Other	694,287		694,287
Total Revenues	$31,512,837	$7,507,709	$39,020,546
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	$12,250,614		$12,250,614
Other O&M	10,662,099		10,662,099
Total O&M	$22,912,713	$0	$22,912,713
Depreciation	5,744,179		5,744,179
Taxes Other Than Income	853,130	$73,140 2/	926,270
Current Income Taxes	(573,936)	1,561,259 2/	987,323
Deferred Income Taxes	370,009		370,009
Total Expenses	$29,306,095	$1,634,399	$30,940,494
Operating Income	$2,206,742	$5,873,310	$8,080,052
Rate Base	$101,190,388		$101,190,388
Rate of Return	**2.181%**		**7.985%**

1/ See Statement A, Page 2.
2/ Reflects taxes at 21% after deducting franchise and revenue taxes at 0.9742%.

Exhibit No.___(TRV-2)

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 55

POWER SUPPLY COST ADJUSTMENT
Rate 50

1. APPLICABILITY:
   This rate schedule constitutes a Power Supply Cost Adjustment (PSCA) provision and specifies the procedure to be utilized to adjust the rates for fuel and purchased power sold under Montana-Dakota's rate schedules in order to reflect the recovery (refund) of the Power Supply Balancing Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:
   The effective date of the PSCA shall be service rendered on and after May 1 each year unless the Wyoming Public Service Commission (Commission) shall otherwise order. The Company will file an application with the Commission to implement the PSCA rate on an interim basis and, if approved by the Commission, the PSCA rate shall continue until a final order is issued by the Commission establishing an effective PSCA rate.

3. POWER SUPPLY COST ADJUSTMENT:
   a. The annual PSCA shall be calculated separately for primary service and secondary service and reflect changes in Montana-Dakota's cost of power supply as compared to the base cost of power supply established in a general rate case for each class.

   b. The cost of power supply shall be the sum of the approved costs incurred in obtaining fuel and purchased power supply for use by all customers served under retail sales rate schedules for the twelve month period ending December 31 each year.

   c. The cost of power supply shall include the following costs for fuel and purchased power supply:

      1. Fuel and fuel handling costs recorded in Account No. 501 and reagent costs recorded in Account 502;
      2. Demand, energy, ancillary services and transmission charges recorded in Account 555; and
      3. Regional Marketing Administration expenses recorded in Account 575; and
      4. The cost of new or existing governmental impositions for electric generation plant emissions, including but not limited to $S0_2$ allowances, carbon taxes and/or carbon allowances and other governmental initiatives related to electric generation plant emissions. Prior to

including any new governmental impositions in the PSCA, the Company will receive approval from the Commission.

d. The base cost of power supply shall consist of all power supply costs established in a general rate case for primary and secondary service stated on a Kwh basis. The base cost of power supply established in Docket No. 20004-___-ER-25 is as follows:

Base Cost of Power Supply Expense	Primary	Secondary
Fuel	1.056¢	1.067¢
Purchased Power	2.846¢	3.355¢
Total	3.902¢	4.422¢

e. The calculation of the power supply cost adjustment is shown on Sheet No. 55.4.

4. POWER SUPPLY BALANCING ACCOUNT:
   a. Items to be included in the Power Supply Balancing Account are:

      1. Amounts under recovered or over recovered for fuel;

      2. Amounts under recovered or over recovered for purchased power supplies each month;

      3. Refunds received with respect to fuel and purchased power supply shall be credited to the Power Supply Balancing Account; and

      4. Interest on the net over or under collected balance in accordance with Subsection 4.b.4.

   b. The amount to be included in the Power Supply Balancing Account in order to reflect the items specified in Subsection 4.a.1-4 shall be calculated as follows:

      1. Montana-Dakota shall first determine each month the unit cost for that month's fuel cost and purchased power costs by PSCA class:

a. Fuel costs shall be allocated to each class based on sales volumes for the month adjusted for the applicable loss factor from the most recently approved general rate case; and

b. Purchased power energy shall be allocated to each class based on sales volumes for the month adjusted for the applicable loss factor from the most recently approved general rate case. Purchased power demand and transmission charges shall be allocated to each class based on the average and excess demand factor that will be updated annually.

2. Montana-Dakota shall then subtract from each month's unit cost (fuel and purchased power) the total cost in rates as set forth in Subsection 6:
   a. For fuel, the difference (which may be positive or negative) shall be multiplied by 85 percent and by the Kwh sold during that month under each applicable rate schedule. The resulting amounts shall be reflected in the Balancing Account (Account 182.3) for primary and secondary service; and
   b. For purchased power, the difference (which may be positive or negative) shall be multiplied by 95 percent and by the Kwh sold during that month under each applicable rate schedule. The resulting amounts shall be reflected in the Balancing Account for primary and secondary service.

3. The amounts in the Power Supply Balancing Account shall be decreased each month by an amount determined by multiplying the currently effective Surcharge Adjustment included in rates for that month by the Kwh sales during that month under each rate schedule. The amount in the account shall be increased in the event the adjustment is a negative amount.

4. The balance in Account 182.3, to which interest will apply, will be the balance at the end of the immediately preceding month. Interest shall be applied to the net over or under collected balance at one-twelfth of the

Commission's Authorized Interest Rate specified in Chapter 1, Section 3(a)(xvii) of the Commission's Rules and recorded in Account 182.3.

The amount amortized each month shall be applied pro rata between the amounts in the Power Supply Balancing Account specified in Subsection 4.a.1. and 2. and the amount related to carrying charges specified in Subsection 4.a.

5. TIME AND MANNER OF FILING:
   a. Each application by Montana-Dakota shall be made by means of revised PSCA and rate schedule tariff sheets identifying the amounts of the adjustments and the resulting currently effective PSCA rates.

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

   c. The application shall be made 60 days prior to the implementation date of May 1 each year.

6. POWER SUPPLY COST ADJUSTMENT:
   The total power supply cost equals 3.902¢ per Kwh for the Primary Service PSCA rate class and 4.422¢ per Kwh for the Secondary Service PSCA rate class. The currently effective PSCA applied to each rate schedule and shown separately on the consumer bill is:

	Primary	Secondary
Base Cost of Power Supply	3.902¢	4.422¢
Power Supply Cost Adjustment	0.000	0.000
Power Supply Balancing Account Adjustment	0.000	0.000
Total PSCA	3.902¢	4.422¢

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 55.4

POWER SUPPLY COST ADJUSTMENT
Rate 50

	Total	Primary	Secondary
Fuel			
501.1 Fuel	$2,362,294	$201,429	$2,160,865
501.4 Fuel Handling	209,716	17,882	191,834
502. Reagents	549,830	46,883	502,947
Total Fuel	$3,121,840	$266,194	$2,855,646
Kwh Sales	292,769,653	25,217,920	267,551,733
Cost per Kwh		$0.01056	$0.01067
Base Fuel Cost		0.01056	0.01067
Difference from Base		$0.000000	$0.000000
Total Change from Base	$0	$0	$0
Amount to be recovered (refunded) from customers (85%)		$0	$0
Purchased Power			
555.1 Energy	$4,176,744	$356,144	$3,820,600
555.6 Capacity	2,826,007	185,168	2,640,839
555.6 Transmission	2,692,378	176,412	2,515,966
Purchased Power	$9,695,129	$717,724	$8,977,405
Kwh Sales	292,769,653	25,217,920	267,551,733
Cost per Kwh		$0.02846	$0.03355
Base Cost of Purchased Power		0.02846	0.03355
Difference from Base		$0.00000	$0.00000
Total Change from Base	$0	$0	$0
Amount to be recovered (refunded) from customers (95%)		$0	$0
Power Suppy Cost Adjustment			
Balance @ 12/31/__		$0	$0
Under (Over) Recovery			
Fuel		$0	$0
Purchased Power		0	0
Net		$0	$0
Amortization			
Interest			
Balancing Account balance @ 12/31/__		$0	$0
Estimated amortization Jan-April			
Net Balance		$0	$0
Projected Kwh sales		25,217,920	267,551,733
PSCA Adjustment		$0.0000	$0.0000
Base PSCA		$0.03902	$0.04422
PSCA Adjustment		0.00000	0.00000
Total PSCA		$0.03902	$0.04422

Date Filed: June 30, 2025

Effective Date: Service rendered on and after

Issued By: Travis R. Jacobson
Vice President – Regulatory Affairs

Docket No.:

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Wyoming

Docket No. 20004-___-ER-25

Direct Testimony

Of

Bradley J. Davison

Q. Please state your name and business address.

A. My name is Bradley J. Davison, 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 Manager of Regulatory Affairs for Montana-Dakota Utilities Co. (Montana-Dakota or Company).

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

A. I am responsible for the preparation of rate recovery mechanisms, fuel cost adjustments, purchased gas cost adjustments, and gas tracking adjustments in each of the jurisdictions in which Montana-Dakota operates.

Q. Please outline your educational and professional background.

A. I graduated from North Dakota State University with a Bachelor of Science degree in Hospitality and Tourism Management, and University of Mary with a Bachelor of Science degree in Accounting. I started my career with Montana-Dakota in 2011 as a Credit and Collections Team Lead.

During my tenure with the Company, I have held various positions of increasing responsibilities including Credit and Collections Supervisor, Revenue Accounting Manager, and now as Regulatory Affairs Manager.

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

A. Yes. I have previously provided testimony before this Commission, the Public Service Commissions of North Dakota and Montana and the Public Utilities Commission of South Dakota.

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

A. The purpose of my testimony is to explain the request for the proposed Reliability and Safey Infrastructure Rider Rate 55 (RSIR), such as how the RSIR will be calculated, the types of projects that will be included, and a projected revenue requirement.

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

A. I am sponsoring Exhibit No.__(BJD-1) in support of the revenue requirement for the proposed RSIR.

Q. Please describe the RSIR and the projects that will be included.

A**.** As previously discussed by Ms. Nicole A. Kivisto and Ms. Tara R. Vesey, Montana-Dakota is proposing the RSIR which is intended to recover new or modified transmission level projects specific to the improvement of power delivery reliability to customers, replacement of pre-1985 underground distribution cables, and upgrades necessary for

wildfire mitigation. The Company has identified three specific projects that the Company plans to include in future RSIR filings. The projects are:

1. An Underground Vintage Cable Replacement Program discussed in detail in the testimony of Mr. Daryl Anderson;
2. A Wildfire Risk Electric Distribution Mitigation Program, also discussed in detail in the testimony of Mr. Anderson; and
3. The 41.6 kV Transmission Line Construction from Sheridan to Dayton discussed in detail in the testimony of Mr. Robert Frank.

These projects provide safety and reliability benefits for customers but are not supported by incremental customer load. Investment in both Underground Vintage Cable Replacement and Wildfire Risk Electric Distribution Mitigation are expected to have continued investment for several years. Transmission level projects, while less routine, are generally significant investments when they do occur. Because there is no incremental load tied to these projects, Montana-Dakota's opportunity to earn its return will be diminished and the capital investment associated with these projects will accelerate future general rate cases.

Q. Describe the revenue requirement supporting the proposed RSIR that is attached as Exhibit No.___(BJD-1).

A. Montana-Dakota has included three projects related to the RSIR for the projected revenue requirement noted above. The revenue requirement for each of these projects is shown on pages 2 and 5 of Exhibit No.___(BJD-1) and has been developed based on the additions to plant in

service for the twelve months beginning in December of the filing year through the following November. The RSIR includes a return requirement on the capital investment based on the rate of return authorized in the Company's most recent general electric rate case, in addition to operation and maintenance expenses, depreciation expense and ad valorem tax expense associated with the eligible projects.

Q. How will the revenue requirement for the RSIR be calculated?

A. As shown in Exhibit No.___(BJD-1), the proposed RSIR would be filed annually with the Commission. This filing would contain a portfolio of projects and costs that the Company will undertake in the upcoming twelve months from December through November. Each annual filing would allow the Commission and other parties to review the projects that were submitted. These monthly project additions would be used to calculate a revenue requirement for the additions based on the currently approved depreciation rates, capital structure, and rate of return. An illustrative example of such costs is included on Exhibit No.___(BJD-1), pages 5 through 7.

The current year costs will include actual costs available prior to filing, and projected costs for the remaining months. A true-up will be included in the following year's update to reflect any over or under recovery based on actual project expenditures from the preceding twelve-month recovery period. Interest will be applied to the net over or under collection at the Commission's authorized interest rate specified in

accordance with Chapter 1, Section 3(a)(xvii) of the Commission's Rules. An illustrative example of such costs is included on Exhibit No.___(BJD-1), pages 2 through 4 and 8.

The resulting revenue requirement shall be divided by the total revenue excluding the Power Supply Cost Adjustment revenue from Montana-Dakota's most recent general electric rate case to determine a percentage adder rate applicable to all rate schedules. An illustrative example of the calculation is included on Exhibit No.___(BJD-1), page 1.

The percentage adder shall be applied to the dollars billed under the Basic Service Charges, Energy Charges and Demand Charges of each rate schedule and identified on a separate line on customers' bills.

Montana-Dakota included the effects of proration on the ADIT balances in the revenue calculation based on the IRS Section 1.167(l)(h)(6), in which the Company prorates ADIT for each month in the "test year" for this rider, subject to a true-up calculation in the following year using actual non-prorated ADIT amounts. Under IRS guidance, the Company is required to do this to avoid normalization violations.

Q. Describe how the projects included in the RSIR would become part of base rates.

When Montana-Dakota files its next general rate case, all projected costs shall be removed from the RSIR and included in the plant in service, thus becoming part of base rates. This would zero out the current revenue requirement included in the RSIR leaving only the true-up

component (remaining RSIR balance) to remain for recovery through the RSIR. This true-up value would either be collected or returned to customers over the subsequent period.

Q. How will customer rates be impacted by the RSIR?

A. Based on the projected investment for 2026 and 2027 of approximately $2.7 million and $11.1 million respectively, as identified by Mr. Anderson and Mr. Frank, a revenue requirement of approximately $670,000 or a percentage adder of approximately 2.63 percent would be proposed as shown on page 1 of Exhibit No.___(BJD-1). This represents a monthly charge to residential customers of approximately $2.27 as shown on page 9 of Exhibit No.___(BJD-1) for illustrative purposes.

Q. What are the long-term impacts of the RSIR for customers?

A. The proposed RSIR provides a mechanism that allows the Company to proactively address wildfire mitigation, replace aging underground wires that are prone to failure, and improve power delivery reliability to customers while delaying costly rate cases. The RSIR will provide customers with more gradual rate increases over time. As discussed above, the projects associated with the RSIR, and the long-term benefits of each of the projects are covered in more detail in the testimony of Mr. Anderson and Mr. Frank. The testimony of Ms. Stephanie Bosch will discuss the proposed RSIR tariff.

Q. When would the first rate be anticipated to be effective under the proposed RSIR?

A. If approved, the Company anticipates filing 60 days prior to the proposed implementation date of December 1, 2026. This filing would reflect qualifying projected 2026 and 2027 projects.

Q. Does this complete your direct testimony?

A. Yes, it does.

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Reliability and Safety Infrastructure Rider
Proposed to be Effective December 1, 2026 - November 30, 2027
Illustrative Example

Projected Revenue Requirement	$519,616	1/
Projected Under/(Over) Recovery as of November 2026	150,372	2/
Net Amount to Recover	$669,988	
Projected Revenues	$25,507,689	3/
Proposed Recovery Rate	2.63%	
Current Recovery Rate	0.00%	
Change in Recovery Rate	2.63%	

1/ Page 5.
2/ Page 8.
3/ From Exhibit No. ___(RJA-2), proposed total revenue excluding fuel.

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Reliability and Safety Infrastructure Rider
Revenue Requirement
2026 Projected
Illustrative Example

	Jan 2026	Feb 2026	Mar 2026	Apr 2026	May 2026	June 2026	July 2026	Aug 2026	Sept 2026	Oct 2026	Nov 2026	Dec 2026	Average Balance
Rate Base													
Plant Balance:													
Vintage URD Line Replacement 4/	$0	$13,046	$91,325	$221,790	$417,488	$678,418	$1,004,581	$1,330,744	$1,526,442	$1,656,907	$1,787,372	$1,787,372	
Wildfire Mitigation 4/	78,001	156,002	234,003	312,004	390,005	468,006	546,007	624,008	702,009	780,010	858,011	936,012	
Total Plant Balance	$78,001	$169,048	$325,328	$533,794	$807,493	$1,146,424	$1,550,588	$1,954,752	$2,228,451	$2,436,917	$2,645,383	$2,723,384	$1,383,297
Accumulated Depreciation:													
Vintage URD Line Replacement 4/	$0	$0	$44	$354	$1,106	$2,521	$4,821	$8,226	$12,738	$17,912	$23,529	$29,588	
Wildfire Mitigation 4/	0	264	793	1,587	2,644	3,966	5,553	7,404	9,519	11,899	14,543	17,452	
Total Accumulated Reserve	$0	$264	$837	$1,941	$3,750	$6,487	$10,374	$15,630	$22,257	$29,811	$38,072	$47,040	$14,705
Net Plant in Service	$78,001	$168,784	$324,491	$531,853	$803,743	$1,139,937	$1,540,214	$1,939,122	$2,206,194	$2,407,106	$2,607,311	$2,676,344	$1,368,592
Deductions:													
Accum DIT - Vintage URD Line Replacement 1/	$601	$1,152	$1,647	$2,088	$2,474	$2,806	$3,082	$3,303	$3,470	$3,581	$3,638	$3,640	
Accum DIT - Wildfire Mitigation 1/	284	544	778	986	1,168	1,325	1,455	1,559	1,638	1,690	1,717	1,718	
Total Rate Base	$77,116	$167,088	$322,066	$528,779	$800,101	$1,135,806	$1,535,677	$1,934,260	$2,201,086	$2,401,835	$2,601,956	$2,670,986	$1,364,730
Return on Rate Base 2/	**$513**	**$1,112**	**$2,143**	**$3,519**	**$5,324**	**$7,558**	**$10,219**	**$12,871**	**$14,646**	**$15,982**	**$17,314**	**$17,773**	**$108,974**
Expenses													
Operating Expenses:													Total
Depreciation - Vintage URD Line 4/	$0	$0	$44	$310	$752	$1,415	$2,300	$3,406	$4,511	$5,175	$5,617	$6,059	$29,589
Depreciation - Wildfire Mitigation 4/	0	264	529	793	1,058	1,322	1,587	1,851	2,115	2,380	2,644	2,909	17,452
Total Expenses	$0	$264	$573	$1,103	$1,810	$2,737	$3,887	$5,257	$6,626	$7,555	$8,261	$8,968	$47,041
Income before Taxes	$0	($264)	($573)	($1,103)	($1,810)	($2,737)	($3,887)	($5,257)	($6,626)	($7,555)	($8,261)	($8,968)	($47,041)
Interest Expense 2/	159	344	662	1,088	1,646	2,336	3,158	3,978	4,527	4,940	5,351	5,493	33,682
Taxable Income	($159)	($608)	($1,235)	($2,191)	($3,456)	($5,073)	($7,045)	($9,235)	($11,153)	($12,495)	($13,612)	($14,461)	($80,723)
Income Taxes 3/	($33)	($128)	($259)	($460)	($726)	($1,065)	($1,479)	($1,939)	($2,342)	($2,624)	($2,859)	($3,037)	($16,951)
Operating Income	$33	($136)	($314)	($643)	($1,084)	($1,672)	($2,408)	($3,318)	($4,284)	($4,931)	($5,402)	($5,931)	($30,090)
Total Revenue Requirement	$480	$1,248	$2,457	$4,162	$6,408	$9,230	$12,627	$16,189	$18,930	$20,913	$22,716	$23,704	$139,064
Gross Revenue Conversion Factor 3/	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828
Total Revenue Requirement	**$614**	**$1,595**	**$3,141**	**$5,320**	**$8,191**	**$11,799**	**$16,141**	**$20,694**	**$24,198**	**$26,733**	**$29,037**	**$30,300**	**$177,763**

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Reliability and Safety Infrastructure Rider
Revenue Requirement
2026 Projected
Illustrative Example

2026 Footnotes:

1/ Monthly Deferred Income Tax activity is 1/12 of 2026 DIT activity. Monthly activity prorated based on DIT proration methodology.

URD Lines		Wildfire Mitigation	
WY DIT Activity:	$7,862	WY DIT Activity:	$3,706
Monthly Activity:	$655	Monthly Activity:	$309

	January	February	March	April	May	June	July	August	September	October	November	December
	91.78%	84.11%	75.62%	67.40%	58.90%	50.68%	42.19%	33.70%	25.48%	16.99%	8.77%	0.27%
Vintage URD Line Replacement:	$601	$551	$495	$441	$386	$332	$276	$221	$167	$111	$57	$2
Wildfire Mitigation:	284	260	234	208	182	157	130	104	79	52	27	1

2/ Proposed in Docket No. 20004-___-ER-25.

ROR:	7.9850%				
Capital Structure:		Ratio	Cost		
	Long Term Debt:	45.274%	5.060%	2.291%	
	Short Term Debt:	3.641%	4.858%	0.177%	2.468%
	Common Equity:	51.085%	10.800%	5.517%	
		100.000%		7.985%	

3/ Tax Rate	21.0000%	(Federal Tax Rate = 21%, WY State Tax Rate = 0%)
Inverse	79.0000%	
Gross Revenue and Franchise Taxes	0.9742%	
Inverse with Revenue Taxes	78.2304%	
Gross Revenue Conversion Factor	1.27828	

4/ Projected addition to Plant in Service. See page 4.

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Reliability and Safety Infrastructure Rider
2026 Projected Projects
Illustrative Example

Safety Projects:

FP-325635 - Vintage URD Line Replacement

Plant Additions: $1,787,372

Plant in Service:	$1,787,372
Depreciation Rate:	4.07% 1/
Annual WY Depreciation:	$72,746
Monthly Depreciation:	$6,062

FP-325636 - Wildfire Mitigation

Plant Additions: $936,012

Plant in Service:	$936,012
Depreciation Rate:	4.07% 1/
Annual WY Depreciation:	$38,096
Monthly Depreciation:	$3,175

1/ Proposed Depreciation Rate per Docket No. 20004-___-ER-25.

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Reliability and Safety Infrastructure Rider
Revenue Requirement
2027 Projected
Illustrative Example

	Jan 2027	Feb 2027	Mar 2027	Apr 2027	May 2027	June 2027	July 2027	Aug 2027	Sept 2027	Oct 2027	Nov 2027	Dec 2027	Average Balance
Rate Base													
Plant Balance:													
Vintage URD Line Replacement 4/	$1,936,432	$2,085,492	$2,234,552	$2,383,612	$2,532,672	$2,681,732	$2,830,792	$2,979,852	$3,128,912	$3,277,972	$3,427,032	$3,576,092	
Wildfire Mitigation 4/	1,014,011	1,092,011	1,170,010	1,248,009	1,326,009	1,404,008	1,482,007	1,560,007	1,638,006	1,716,005	1,794,005	1,872,004	
46KV Line Dayton to Sheridan 4/	0	0	0	0	0	0	0	0	0	0	0	8,417,442	
Total Plant Balance	$2,950,443	$3,177,503	$3,404,562	$3,631,621	$3,858,681	$4,085,740	$4,312,799	$4,539,859	$4,766,918	$4,993,977	$5,221,037	$13,865,538	$4,900,723
Accumulated Depreciation:													
Vintage URD Line Replacement 4/	$35,647	$42,212	$49,282	$56,857	$64,937	$73,523	$82,614	$92,211	$102,312	$112,919	$124,032	$135,649	
Wildfire Mitigation 4/	20,625	24,062	27,764	31,731	35,961	40,457	45,216	50,240	55,529	61,081	66,899	72,980	
46KV Line Dayton to Sheridan 4/	0	0	0	0	0	0	0	0	0	0	0	0	
Total Accumulated Reserve	$56,272	$66,274	$77,046	$88,588	$100,898	$113,980	$127,830	$142,451	$157,841	$174,000	$190,931	$208,629	$125,395
Net Plant in Service	$2,894,171	$3,111,229	$3,327,516	$3,543,033	$3,757,783	$3,971,760	$4,184,969	$4,397,408	$4,609,077	$4,819,977	$5,030,106	$13,656,909	$4,775,328
Deductions:													
Accum DIT - Vintage URD Line Replacement 1/	$5,086	$6,412	$7,604	$8,666	$9,594	$10,393	$11,058	$11,589	$11,991	$12,259	$12,397	$12,401	
Accum DIT - Wildfire Mitigation 1/	2,475	3,169	3,793	4,349	4,835	5,253	5,601	5,879	6,089	6,229	6,301	6,303	
Accum DIT - 46KV Line 1/	5,070	9,716	13,893	17,616	20,870	23,670	26,001	27,863	29,271	30,210	30,694	30,709	
Total Rate Base	$2,881,540	$3,091,932	$3,302,226	$3,512,402	$3,722,484	$3,932,444	$4,142,309	$4,352,077	$4,561,726	$4,771,279	$4,980,714	$13,607,496	$4,738,219
Return on Rate Base 2/	**$19,174**	**$20,574**	**$21,974**	**$23,372**	**$24,770**	**$26,167**	**$27,564**	**$28,959**	**$30,354**	**$31,749**	**$33,143**	**$90,547**	**$378,347**
Expenses													
Operating Expenses:													Total
Depreciation - Vintage URD Line 4/	$6,059	$6,565	$7,070	$7,575	$8,080	$8,586	$9,091	$9,596	$10,102	$10,607	$11,112	$11,618	$106,061
Depreciation - Wildfire Mitigation 4/	3,173	3,437	3,702	3,966	4,231	4,495	4,760	5,024	5,288	5,553	5,817	6,082	55,528
Depreciation - 46KV Line 4/	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expenses	$9,232	$10,002	$10,772	$11,541	$12,311	$13,081	$13,851	$14,620	$15,390	$16,160	$16,929	$17,700	$161,589
Income before Taxes	($9,232)	($10,002)	($10,772)	($11,541)	($12,311)	($13,081)	($13,851)	($14,620)	($15,390)	($16,160)	($16,929)	($17,700)	($161,589)
Interest Expense 2/	5,926	6,359	6,791	7,224	7,656	8,088	8,519	8,951	9,382	9,813	10,244	27,986	116,939
Taxable Income	($15,158)	($16,361)	($17,563)	($18,765)	($19,967)	($21,169)	($22,370)	($23,571)	($24,772)	($25,973)	($27,173)	($45,686)	($278,528)
Income Taxes 3/	($3,183)	($3,436)	($3,688)	($3,941)	($4,193)	($4,446)	($4,698)	($4,950)	($5,202)	($5,454)	($5,706)	($9,594)	($58,491)
Operating Income	($6,049)	($6,566)	($7,084)	($7,600)	($8,118)	($8,635)	($9,153)	($9,670)	($10,188)	($10,706)	($11,223)	($8,106)	($103,098)
Total Revenue Requirement	$25,223	$27,140	$29,058	$30,972	$32,888	$34,802	$36,717	$38,629	$40,542	$42,455	$44,366	$98,653	$481,445
Gross Revenue Conversion Factor 3/	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828	1.27828
Total Revenue Requirement	**$32,242**	**$34,693**	**$37,144**	**$39,591**	**$42,040**	**$44,487**	**$46,935**	**$49,379**	**$51,824**	**$54,269**	**$56,712**	**$126,106**	**$615,422**

December 2026 included in Revenue Requirement: $30,300
January - November 2027 included in Revenue Requirement: $489,316
Total Projected Revenue Requirement: $519,616

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Reliability and Safety Infrastructure Rider
Revenue Requirement
2027 Projected
Illustrative Example

2027 Footnotes:

1/ Monthly Deferred Income Tax activity is 1/12 of 2027 DIT activity. Monthly activity prorated based on DIT proration methodology.

URD Lines		Wildfire Mitigation		46KV Line	
WY DIT Activity:	$18,910	WY DIT Activity:	$9,900	WY DIT Activity:	$66,287
Monthly Activity:	$1,576	Monthly Activity:	$825	Monthly Activity:	$5,524

	January	February	March	April	May	June	July	August	September	October	November	December
	91.78%	84.11%	75.62%	67.40%	58.90%	50.68%	42.19%	33.70%	25.48%	16.99%	8.77%	0.27%
Vintage URD Line Replacement:	$1,446	$1,326	$1,192	$1,062	$928	$799	$665	$531	$402	$268	$138	$4
Wildfire Mitigation:	757	694	624	556	486	418	348	278	210	140	72	2
Build 46KV Line Dayton to Sheridan	5,070	4,646	4,177	3,723	3,254	2,800	2,331	1,862	1,408	939	484	15

2/ Proposed in Docket No. 20004-___-ER-25.

ROR: 7.9850%

Capital Structure:	Ratio	Cost		
Long Term Debt:	45.274%	5.060%	2.291%	
Short Term Debt:	3.641%	4.858%	0.177%	2.468%
Common Equity:	51.085%	10.800%	5.517%	
	100.000%		7.985%	

3/ Tax Rate	21.0000%	(Federal Tax Rate = 21%, WY State Tax Rate = 0%)
Inverse	79.0000%	
Gross Revenue and Franchise Taxes	0.9742%	
Inverse with Revenue Taxes	78.2304%	
Gross Revenue Conversion Factor	1.27828	

4/ Projected addition to Plant in Service. See page 7.

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Reliability and Safety Infrastructure Rider
2027 Projected Projects
Illustrative Example

Safety Projects:

FP-325635 - Vintage URD Line Replacement

Plant Additions: $1,788,720

Plant in Service:	$1,788,720
Depreciation Rate:	4.07% 1/
Annual WY Depreciation:	$72,801
Monthly Depreciation:	$6,067

FP-325636 - Wildfire Mitigation

Plant Additions: $935,992

Plant in Service:	$935,992
Depreciation Rate:	4.07% 1/
Annual WY Depreciation:	$38,095
Monthly Depreciation:	$3,175

FP-316135 - Build 46KV Line Dayton to Sheridan

Plant Additions: $8,417,442

Plant in Service:	$8,417,442
Depreciation Rate:	3.08% 1/
Annual WY Depreciation:	$259,257
Monthly Depreciation:	$21,605

1/ Proposed Depreciation Rate per Docket No. 20004-___-ER-25.

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Reliability and Safety Infrastructure Rider
Calculation of RSIR Acount Balance
Illustrative Example

	Revenue Requirement	Revenue Collected	(Over)/Under Collection	Cumulative (Over)/Under	Rate 1/	Interest 2/	Total Cumulative (Over)/Under
December 2025				$0			
January 2026	$614	$0	$614	614	6.46%	$3	$617
February	1,595	0	1,595	2,209	6.46%	12	2,224
March	3,141	0	3,141	5,350	6.46%	29	5,394
April	5,320	0	5,320	10,670	6.46%	57	10,771
May	8,191	0	8,191	18,861	6.46%	102	19,064
June	11,799	0	11,799	30,660	6.46%	165	31,028
July	16,141	0	16,141	46,801	6.46%	252	47,421
August	20,694	0	20,694	67,495	6.46%	363	68,478
September	24,198	0	24,198	91,693	6.46%	494	93,170
October	26,733	0	26,733	118,426	6.46%	638	120,541
November	29,037	0	29,037	147,463	6.46%	794	150,372
Total	**$147,463**	**$0**				**$2,909**	

1/ Interest calculated pursuant to Rate 50 and Chapter 1, Section 2(a)(xv) of the Wyoming Public Service Commission's Rules and Regulations.

2/ Based on prior month ending balance.

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Residential Electric Service Rate 10
Bill Impact of RSIR Rate 55
Illustrative Example

		Proposed Rates				Proposed Rates with RSIR					Bill Change	
	kWh	Basic Service Charge	Energy	PSCA	Total	Basic Service Charge	Energy	RSIR	PSCA	Total	$ Increase	% Increase
January	1,100	$35.96	$69.20	$48.64	$153.80	$35.96	$69.20	$2.77	$48.64	$156.57	$2.77	1.8%
February	900	32.48	56.62	39.80	128.90	32.48	56.62	2.34	39.80	131.24	2.34	1.8%
March	800	35.96	50.32	35.38	121.66	35.96	50.32	2.27	35.38	123.93	2.27	1.9%
April	800	34.80	50.32	35.38	120.50	34.80	50.32	2.24	35.38	122.74	2.24	1.9%
May	700	35.96	44.04	30.95	110.95	35.96	44.04	2.10	30.95	113.05	2.10	1.9%
June	600	34.80	37.75	26.53	99.08	34.80	37.75	1.91	26.53	100.99	1.91	1.9%
July	800	35.96	50.32	35.38	121.66	35.96	50.32	2.27	35.38	123.93	2.27	1.9%
August	1,000	35.96	62.91	44.22	143.09	35.96	62.91	2.60	44.22	145.69	2.60	1.8%
September	800	34.80	50.32	35.38	120.50	34.80	50.32	2.24	35.38	122.74	2.24	1.9%
October	700	35.96	44.04	30.95	110.95	35.96	44.04	2.10	30.95	113.05	2.10	1.9%
November	600	34.80	37.75	26.53	99.08	34.80	37.75	1.91	26.53	100.99	1.91	1.9%
December	900	35.96	56.62	39.80	132.38	35.96	56.62	2.43	39.80	134.81	2.43	1.8%
Total	9,700	$423.40	$610.21	$428.94	$1,462.55	$423.40	$610.21	$27.18	$428.94	$1,489.73	$27.18	1.9%
Average	808								Average Monthly Bill Impact		$2.27	

Rate 10 Proposed

Basic Service Charge	$1.160	per day
Energy Charge	$0.06291	per kWh
Power Supply Cost Adjustment	$0.04422	per kWh

Rate 10 Proposed with RSIR

Basic Service Charge	$1.160	per day
Energy Charge	$0.06291	per kWh
Power Supply Cost Adjustment	$0.04422	per kWh
Reliability & Safety Infrastructure Rider	2.63%	of amounts billed under BSC, Energy and Demand Charge

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Wyoming

Docket No. 20004-___-ER-25

Direct Testimony
of
Ronald J. Amen

June 30, 2025

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 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 issues, 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 numerous 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 in Appendix A.

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 rate design proposals filed by Montana-Dakota in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation
- Montana-Dakota's COSS
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Montana-Dakota's Rate Design Proposals
- Customer Bill Impacts

Q. Please provide a list of the exhibits and schedules supporting your testimony.

A. I am sponsoring Statement K, Statement L, and the following exhibits:

- Exhibit No.____(RJA-1), Proposed Revenue Allocation
- Exhibit No.____(RJA-2), Summary of Rate Design Results
- Exhibit No.____(RJA-3), Bill Comparison Annual Effects (Residential)

II. THEORETICAL PRINCIPLES OF COST ALLOCATION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities to conduct 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 include all costs that do not vary with the amount of energy consumed by customers and constitute the vast majority of the cost to provide service.

Variable costs include only those costs that vary with the amount of energy consumed by the customers. In other words, variable costs relate directly to how much power is actually consumed; these costs include fuel, the energy

component of purchased power costs, reagents used in generation for the operation of emission control systems, and any O&M costs directly related to energy production.

All other costs incurred by the utility are fixed costs because the utility must incur them in order to be capable of providing service whether or not customers actually consume any energy.

Q. Please discuss the principle of cost causation.

A. Cost studies are a basic tool for ratemaking. Just and reasonable rates must avoid undue discrimination and must reflect the principle of “user pays,” also known as “cost causation,” which is another way of saying those who cause the costs should pay the costs. The development of unbundled costs permits regulatory review of the costs that are the same on average for customers in the class. The term “on average” is used because no two customers are exactly alike. Therefore, costs are determined, and cost-based rates are set, for “typical” customers grouped by similar demand and usage patterns.

If those costs are not recovered in the customer charge or basic service fee as they should be, the customers with more than average energy consumption subsidize the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

In order for rates to be efficient the concept of customers being charged for the distinct services they use is important since different customers use different services. Further, the costs of those services may be different because

of the different load characteristics of customers in a class. Both cost allocation and rate design play a role in efficient rates.

A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system.

Q. Why is the principle of cost causation important?

A. Cost causation is the key element to selecting an allocation method. This has been the standard by which an allocation method is evaluated, and it continues to be the gold standard for assessing cost allocation. The principle of cost causation is also relevant for analysis within classes of customers where each customer must have rates that, on average, match the cost of service for that customer.

Q. What are the basic steps in developing a cost of service study?

A. Cost of service studies use a three-step process as follows:

1. Functionalization
2. Classification
3. Allocation

Q. Please explain the functionalization process.

A. A systematic process for identifying functions is used based on the traditional categories of production, transmission, distribution, and customer. To the extent permitted by the accounting data, this functionalization may include subcategories such as primary distribution and secondary distribution and

directly assigned dollars based on unique facilities that need to be assigned rather than allocated. The process of functionalization has become a more robust and simplified process with the use of accounting data as reported under a uniform system of accounts ("USOA"). That is not to say that all of the issues have been resolved. Certain accounts such as intangible plant still require some analysis to functionalize individual cost elements in the account for some utilities. The typical functions used in a cost study are as follows:

- Production/Supply
- Transmission
- Distribution
- General, Common, and Intangible

Each of these functions is described below.

The Production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The Transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the distribution grid and to move power from generation to load.

The Distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. In recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and

customer service accordingly, plant and expenses caused by individual customers.

The General, Common, and Intangible function includes office buildings and equipment, vehicles, materials and supplies, the Customer Care and Billing (CC&B) system, and other engineering and communications software systems.

Q. Please describe the cost classification step.

A. Cost classification is driven by as detailed an analysis as the accounting data permits. Costs are classified as demand, energy, and customer. Only costs that vary with energy are classified as energy. The costs classified as demand are those costs that are a function of some measure of demand. Customer costs are those costs that vary with the number of customers. For some of the costs associated with the distribution system, costs must be split between the portion that is demand related and the portion that is customer related. That split is based on the principles of cost causation, as discussed above. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built, and operated.

Q. Please elaborate on the nature of the cost classification categories.

A. *Demand* costs are capacity related costs associated with plant that is designed, installed, and operated to meet maximum electric usage requirements such as larger transformers or more localized distribution facilities, which are designed to satisfy individual customer maximum demands. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Energy costs are those costs that vary directly with the production of energy such as fuel costs; other fuel related expenses or purchased power expense.

Customer costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer costs are largely a function of the number and density of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Q. Can costs be classified into more than one category?

A. Yes. For example, as mentioned earlier, some distribution costs may have both a demand and a customer cost component.

Q. Please describe the allocation process.

A. Allocation is based on the factors that cause costs to be incurred. Cost studies use two types of allocation factors: external factors and internal factors. External allocation factors are based on direct knowledge from data in the utility's accounting and other records such as the load research data. Energy allocation factors are based on the class energy consumption and adjusted for losses to equate to total energy production. Another example of an external allocation factor is allocation of distribution system costs, both the demand and customer components. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers, and fixtures, overhead and underground conductors, transformers, service lines and meters. Once assigned to distribution, the poles and conductors are allocated using the

minimum system to classify the costs between demand and customer related costs and then are allocated on external allocation factors. Demand allocation factors are based on class load factors that are used to calculate each class's average demand and the non-coincident peak demand for each class. Internal allocation factors are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors.

Q. What are the measures of demand that may be used in cost allocation?

A. The demands used to develop allocation factors essentially fall into three fundamental categories as follows:

1. Coincident Peak ("CP") Methods
2. Non-Coincident Peak ("NCP") Methods
3. Average and Excess Demand ("AED") Methods.

Q. Please briefly summarize the basic assumptions underlying each potential allocator.

A. The following table summarizes the basic provisions of each category of allocation methods:

Table 1

Cost Allocation Methods Summary

Allocation Method	Assumption about Cost	Allocation Factor
CP	Peak loads drive costs	Class coincident demand
AED	Peak loads and energy usage drive costs	NCP and load factor
NCP	Class or customer peaks drive costs	Class or customer NCP

Q. What methodology was used in the preparation of the Montana-Dakota cost of service study?

A. A combination of a) the AED demand method for production and transmission costs, and b) the class NCP demands at the generation and distribution levels were used in developing the Montana-Dakota COSS. These demand allocations are consistent with prior Montana-Dakota cost of service studies in Wyoming.

III. MONTANA-DAKOTA'S COST OF SERVICE STUDY

A. Production and Transmission Plant

Q. Please describe the nature and characteristics of Montana-Dakota's Production and Transmission plant.

A. The investment in the production and transmission plant is comprised primarily of the investment in the Wygen III generating facility, which was allocated on the AED demand allocator to account for the contribution of each class based on a combination of the classes' average demand and the difference between the total system peak demand and the average demand, as allocated to each class based on its non-coincident demand (NCP) in excess of the average demand.

B. Characteristics of Distribution Plant

Q. Please discuss the nature and characteristics of distribution plant.

A. The Montana-Dakota system distribution plant consists of different facilities that have different cost causation factors. The reason for this conclusion is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility costs are directly the result of the individual customer and are caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component, like transformers.

Distribution costs differ based on the portion of the system used by different classes of service. Further, not all customers use the same level of distribution facilities. For example, customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three-phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require extra facilities to serve a load based on unique load characteristics such as low power factor or frequency regulation for intermittent loads. When customers who have common load characteristics, “homogeneous” load characteristics, they may warrant a separate class of service. This is particularly important to recognize that partial requirements customers require their own class of service because of the unique load characteristics of this type of customer.

For distribution costs found in Account Nos. 364 (Poles, Towers & Fixtures), 365 (Overhead Conductor), 366 (Underground Conduit), 367 (Underground Conductor), 368 (Line Transformers), 369 (Services), 370 (Meters), 371 (Installations on Customer Premises), and 373 (Street Lighting), either all or a portion of the costs are customer related because they are caused by customers. There is no basis for arguing that Account Nos. 369 – 373 are not customer related. For Account No. 369 – Services, each customer has a service designed to meet that customer’s own load characteristics. The service line is dedicated to the customer to meet the load of the customer premise. Services

are dedicated to a customer and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge, the result is not just and reasonable and is a case of undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system.

Electricity will not flow into a premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex and the cost of meter sets increase. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system without and cannot receive service without a minimum level of distribution services provided through the assets in Account Nos. 364 – 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The concept of a minimum system assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs.

The costs of Installation on Customer Premises (Account No. 371) were directly assigned to Outdoor Lighting and the costs of Street Lighting and Signal Systems (Account No. 373) were directly assigned to Municipal Lighting.

C. Minimum Distribution System

Q. Is the method used by the Company to determine a customer cost component of a distribution system a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-size unit of plant investment. The zero-intercept method determines the costs associated with zero loads by valuing the costs of all assets in an account and conducting regression analysis of cost on current-carrying capacity or demand rating to establish the cost of a zero-load system. The most commonly installed, minimum-sized unit of plant method classifies the costs of a hypothetical minimum-size version of the utility's distribution system capable of connecting to all customers as customer-related, then classifies all remaining costs as demand-related. Each of the accounts (e.g., Account Nos. 364 – 367) are examined to identify the smallest, most commonly used type of pole, conductor, etc. The unit cost of this minimum-size plant is then multiplied by the total number of units of that plant type. A comparison with the value of all the assets in the account yields the minimum-sized result. Both methods are acceptable to the industry. One of the more commonly accepted literary references relied upon when preparing embedded cost of service studies is the Electric Utility Cost Allocation Manual, by John J.

Doran et al, National Association of Regulatory Utility Commissioners ("NARUC").

Q. Of the two methods, which has Montana-Dakota used to determine its minimum distribution system?

A. Montana-Dakota uses the minimum-size method for Account Nos. 364 – 367 and the zero-intercept method to classify transformers (Account 368). The Company's method for Account Nos. 364 – 367 uses a modeling approach that creates representative one-mile minimum and normal underground and overhead systems, and then calculates the current replacement cost of each. The one-mile minimum underground and overhead systems are regarded as customer-driven systems, while the difference in cost between a normal and a minimum system is deemed demand-driven. This approach has been used by Montana-Dakota in prior COSS studies in Wyoming and its other jurisdictions.

Q. Does the one-mile minimum system approach provide a reasonable representation of customer-driven distribution system costs?

A. Yes. The one-mile-of-circuit approach attempts to construct a realistic representation of a Montana-Dakota circuit under two scenarios and applies the standard minimum system logic that uses the smallest feasible equipment size to serve that circuit as an acceptable way to identify customer-driven cost. Montana-Dakota's approach of creating a hypothetical one-mile circuit is a realistic proxy for circuits in Montana-Dakota's service territory.

Q. How does Montana-Dakota apply the one-mile minimum system methodology in its COSS study?

A. Montana-Dakota subdivides Account Nos. 364-367 into their customer-related and demand-related portions based on the results of the minimum system study.

Q. How does Montana-Dakota separate the two classification components for Account No. 368, line transformers?

A. Montana-Dakota uses zero-intercept regression analysis to determine the customer component of transformers. Specifically, the zero intercept costs were multiplied by the number of transformers at or below 50 kVA. The ratio of that amount to the total replacement cost of all transformers was 72.5%, which was used for establishing the customer component of transformer plant.

Q. Why does Montana-Dakota use the zero-intercept method for Account No. 368, but the minimum-size method for the other accounts described above?

A. Line transformers are not readily included in the methodology based on the representative one mile of circuit. Line transformers offer, by their standard equipment types, a more readily developed zero-intercept analysis.

The results of Montana-Dakota's analyses appear in **Table 2** below. The values for the customer and demand related components of FERC accounts 364-368 are inputs to the COS model. Note that, as with other utilities, FERC account 366, underground conduit, is assumed to have the same classification properties as underground conductors.

Table 2

Minimum Size/Minimum Intercept Results

FERC A/C	Account Name	Customer	Demand
364	Poles	61%	39%
365	Overhead Conductors	69%	31%
367	Underground Conductors	57%	43%
368	Line Transformers	73%	27%

D. Allocation of Customer Costs

Q. Please discuss the allocation of customer related costs.

A. There are costs other than distribution plant that are customer related and should be included in the customer cost allocation. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer costs. In addition, where all of a plant account is allocated as customer related, all of the associated O&M costs should also be allocated to customer costs. Second, customer service-related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities and other types of facilities such as the meter shop, stores, tools, and equipment. Fourth, a portion of administrative and general expenses should be allocated to customer costs as well. The allocation of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but pension and benefits cost and other items related directly to employee costs.

E. Distribution Plant

Q. What method does Montana-Dakota employ to allocate demand-related distribution costs?

A. Montana-Dakota allocates demand-related distribution costs primarily by reference to class shares of noncoincident peak ("NCP") demand. Load research reveals each class's single maximum level of consumption over the course of a

year. The “One NCP” allocator is simply each class’s share of the sum of these values. (The “One” signifies a single annual maximum value.) Investment in distribution plant occurs in response to the increase in peak demands of customers on individual feeder lines, such peak demands do not necessarily correspond with the timing of system peak demands. Accordingly, measuring each customer class’s peak and then estimating the class’s share in the sum of the peaks across all classes, is a reasonable way to judge responsibility for demand-related cost causation applying to distribution investment.

The Montana-Dakota COSS model uses two NCP allocators, one applicable at the generation level and another at the secondary service level. The “Non-Coincident KW @ Supply” allocator is based on the peak demands of all customers and allocates demand related costs associated with land, station equipment, poles, conductors, and conduit. The “Non-Coincident KW @ Supply (Secondary)” allocator is based on the peak demands of secondary distribution customers and allocates demand-related line transformer costs.

Q. What is the underlying evidentiary basis for Montana-Dakota’s One NCP allocators?

A. Montana-Dakota has developed load research data for its customer classes. For each class, Montana-Dakota developed sample usage, coincident peak, and class non-coincident peak data for calendar 2024, then scaled the values based on billed kWh. This results in demand values that preserve observed load factors of the load research sample. Demand values were calculated that produce load factors identical to the class with which each class lacking interval data was matched. For the test year (2024), Montana-Dakota produced kWh forecasts and demand values that yielded load factors identical to those of the historical data.

Q. In your opinion is Montana-Dakota's load research process reasonable?

A. Yes. This application of load research data to generate demand-related allocators is standard practice; it is consistent with other utilities' practices.

Q. How does Montana-Dakota allocate customer-related distribution costs?

A. Montana-Dakota uses allocators based on customer numbers, weighted by costs for certain cost categories, for various types of assets and expenses. The Company develops several customer-related allocation factors: total customer numbers; customer less outdoor lighting; customer meters, weighted by an index of meter costs; customer service drops, weighted by service cost; customer transformers, weighted by transformer cost; and customer accounts, weighted by the cost of customer support. The Company's forecasts of test year customer numbers and meter numbers underpin these allocation factors.

F. Other Allocation Factors

Q. Please describe other types of allocation factors within the COSS.

A. There are numerous other allocation factors in the COSS. Fuel and purchased power expenses are allocated based on energy at generation as are certain fuel related O&M costs. Purchased power capacity also has a demand component, which is allocated on AED. O&M costs for the various plant functions are allocated as the associated plant is allocated. There are a number of internal allocation factors that distribute costs according to the factor or factors causing those costs. Thus, rate base items like provision for pension, benefits, and post-retirement costs, are allocated on O&M excluding fuel and purchased power. General, Common, and intangible plant investments are allocated on Production, Transmission and Distribution plant. General, Common-Intangible-CC&B and PCAD are allocated on customers excluding Outdoor Lighting.

G. Summary of the Allocated Cost of Service Study

Q. Are the allocation factors utilized in the embedded class cost of service study consistent with the allocation factors underlying currently authorized rates established in the Company's last electric rate case?

A. Yes. The derivation and application of the allocation factors is consistent with the embedded class cost of service study submitted in the last rate case. A summary description of each of the allocation factors is provided in workpapers.

Q. Please summarize the results of the recommended cost of service study.

A. The following Table 3 provides a high-level summary of the results of the COSS presented in Statement K, pages 1-6. Table 3 shows the rate of return for each rate class based on current rates as well as the system overall return and the revenue deficiency or excess for each rate class at the uniform system rate of return.

Table 3

Rate of Return and Revenue Excess/(Deficiency) by Rate Class

Customer Class	Rate of Return By Class	Revenue Excess or (Deficiency)
Residential Service	2.14%	($4,248,033)
Residential Controlled Service	(0.08%)	($212,425)
Small General Service - Primary	(11.59%)	($18,533)
Small General Service - Secondary	1.19%	($1,588,569)
Small General Controlled Service	(0.94%)	($3,868)
Irrigation Service	(7.87%)	($605,565)
Irrigation Service - Time of Day	(9.29%)	($29,841)
Large Power Standby Service	32.32%	$2,002
Large General Service - Primary	3.86%	($249,764)
Large General Service - Secondary	4.95%	($557,299)
Outdoor Lighting	8.05%	$469
Public Lighting	8.26%	$3,717
Total Wyoming Electric	2.18%	($7,507,709)

Q. Do these results provide guidance for the allocation of revenue requirements in this case?

A. Yes. Cost of service is a useful tool for determining the allocation of the revenue deficiency to each rate class. Cost of service is not, however, the only consideration in determining the portion of the revenue deficiency allocated to each rate class. Other considerations include principles such as gradualism, competitive considerations, standalone costs and avoiding or minimizing the potential for compromising the integrity of current rate classes.

Q. Has Montana-Dakota taken the above factors into account in recommending the level of rate increase for rate classes?

A. Yes. The process for determining the revenue increase for each class is addressed in Section VII of this testimony.

Q. Please explain the COSS information contained in Statement K.

A. Statement K, consists of 6 pages and provides a report titled “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 7.99 percent were to be earned for the demand, energy, and customer cost components of each rate schedule. The individual rate schedule’s pro forma rates of return before allocation of the requested increase is also shown on Statement K.

A summary of the results of allocation of the rate base and income statement items to the rate classes is provided in Statement K, Schedule K-1, pages 1 – 12.

Statement K, Schedule K-2, pages 1 – 132, titled “Embedded Class Cost of Service Study”, provides the complete rate base and income statement as

allocated to each rate schedule including the allocation factor applied to each amount.

The allocation factors used to allocate the total Wyoming electric amount to each class and cost component are provided in the Allocation Factor Report, Statement K, Schedule K-3, pages 1-18.

The COSS is based on the Wyoming results of electric operations recorded for the 12 months ended December 31, 2024, as adjusted to reflect pro forma adjustments sponsored by Company witness Ms. Tara R. Vesey.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design utilized in development of the Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service,

(2) Efficiency,

(3) Value of Service,

(4) Stability/Gradualism,

(5) Non-Discrimination,

(6) Administrative Simplicity, and

(7) 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.[1]

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 electric power 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 electric 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

[1] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

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.

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 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.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices to 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 was 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. As noted above, there are tensions between cost and value of service principles. 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 rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate 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 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 must 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 base rate revenue increase of $7,507,709 to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for Montana-Dakota's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Montana-Dakota's interclass revenue proposal?

A. Yes. Using Montana-Dakota's proposed revenue increase, and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Montana-Dakota personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that I evaluated under Montana-Dakota's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost ratio for each class was equal to 1.00 (Unity), as shown in Exhibit No____(RJA-1), 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-fuel revenues (see *Scenario A, Equal Percentage Increase (System Average)*, 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 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). 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 revenue to cost ratios for Outdoor Lighting Rate 24, Large General Secondary Rate 37, and Public Lighting Rate 42 (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 as shown in Exhibit No.___ (RJA-1), *Scenario C: Maximum Increase of 1.5 Times*

System, Minimum 0.75 times system with no Controlled Rate subsidy. The first step of this revenue apportionment was to establish a maximum increase of 1.5 times the system average that was applied to the classes that required a greater amount than that to be brought to full cost of service. The second step was to apply a minimum increase of 75% of the system average increase to the classes that required less than that amount to be brought to full cost of service. The remaining classes were increased to cost of service, then any remaining revenue shortfall was allocated to these classes on an equal percentage of margin basis.

As a final step, the Residential and Small General controlled rates (Rate 11 and Rate 22) were further increased to their full cost of service with the additional revenue offsetting the revenue allocation to Rate 10 and Rate 20, respectively. The controlled rates' revenue has fallen far below their cost to serve, however there is no justification for perpetuating a subsidy for either of these rates. Furthermore, the Company is proposing to merge Rate 22 into Rate 20 in this case and is planning to merge Rate 11 into Rate 10 in a future case, as discussed in the direct testimony of Company witness Ms. Stephanie Bosch.

In the case of the Residential Service class, the revenue adjustment ensures their proposed rates will move class revenues closer to COSS for the class.

The Small General Service Primary, Small General Controlled, and Irrigation Service customer classes' parity ratios were well below Unity (1.00) at the Company's proposed ROR of 7.99%. Therefore, the maximum revenue increase of 62.57% (which is 150% of the system average increase of 41.71%) is proposed for these respective classes, which resulted in modest movement toward Unity.

The Large General Service Primary and Large General Service Secondary customer classes required less than the minimum revenue increase to reach their cost of service. Therefore these classes received the minimum revenue increase of 31.28% to (0.75 time the system average increase of 41.71%) which resulted in meaningful movement towards parity.

The COSS results for the remaining customer classes indicate their respective class rates of return are above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue decreases in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00, as shown in Exhibit No.___ RJA-1 under *Revenues at Equalized Rates of Return)*, the resulting customer impact implications for the Small General - Primary, Small General Controlled, and Irrigation Service classes 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 minimum revenue adjustments of 31.28% will mean these classes parity ratio levels will converge toward unity.

In summary, this preferred revenue allocation approach resulted in reasonable movement toward Unity or 1.00 for all classes, while providing moderation of the customer bill impacts 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 apportionment of the overall system revenue increase, and modest reduction in the existing class rate subsidies, is desirable.

Q. Please discuss the information provided in Statement L.

A. Statement L, titled Allocation of Revenues, presents summaries by customer class of the proposed revenue increase. This Statement displays the revenues calculated under the present and proposed rates for each customer class. The proposed revenue increase components by rate class and corresponding percentages are also shown.

The allocation of the total target revenue increase of $7,507,709 to the respective rate schedules is presented on page 4 of 17 of Statement L. The pro forma 2025 billing determinants are shown on page 1 of 17, and the embedded cost of service by rate class prior to the proposed revenue increase are presented on page 3 of 17 of the Statement. The target revenue increase as a percentage of total class revenues are shown on Statement L, page 4 of 17. Pages 5 through 16 of Statement L provide the derivation of the proposed rates for each Rate Schedule, and page 17 shows bill impacts for Residential Rate 10.

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

A. As shown on Exhibit No. ____(RJA-2) and Table 4 below, the proposed percentage increase to each of the classes associated with the revenue requirement to be collected through base retail rates is as follows:

Table 4

Increase in Revenues to Be Collected Through Base Retail Rates[2]

Class	Percent Increase
Residential	26.00%
Small General Service	30.74%
Irrigation Service	40.10%
Large General Service	15.15%
Lighting	15.81%
System Total	24.36%

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 adjusting the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service.

Q. Please describe the process to determine the proposed changes to the Basic Service Charges and the other rate components for the respective tariff schedules.

The following process was used to determine the rate components for each of the rate schedules:

1. The first step was to establish the Basic Service Charge by considering the customer costs identified in the COSS and the Demand Charge

[2] Statement L, page 4 of 17.

based on the demand costs identified in the COSS, for those rate schedules where demand metering is warranted.

2. The second step was to deduct the revenues to be recovered under the Basic Service Charge, Demand Charge, seasonal or service level differential and Base Fuel and Purchased Power components for each rate schedule.

3. The Energy Charge component was then determined by dividing the revenues remaining to be collected by the proforma sales under the applicable rate schedule.

The calculations described above are provided for each rate schedule on pages 6 – 16 of Statement L. A Summary of the Proposed Charges for each rate schedule is provided on Statement L, page 5.

Q. Please describe the Company's current Residential Rate 10.

Residential Rate 10 customers have a Basic Service Charge per day and an inverted rate block energy charge, where the price for the first 1000 kWh of usage each month is lower than additional usage over 1000 kWh.

Q. How does the Company propose implementing the price change for residential customers?

The Basic Service Charge for Residential Rate 10 is proposed to increase from $0.769 to $1.160 per day resulting in a monthly charge of $35.28 which is 113 percent of the customer-related unit cost of service of $31.27 per month, allowing for recovery of a portion of the fixed demand-related costs in the fixed charge.

The Company also proposes eliminating the inverted rate block, combining the energy charges into a flat energy rate on customer bills at a price

of $0.06291 per kWh for all kWh. As shown on Exhibit No. ____ (RJA-3), a typical residential customer will experience an average monthly bill increase of $27.84.

Q. Why is the Company proposing to eliminate the energy charge tiered block rate?

A. The Company is proposing to eliminate the inverted block energy rate because there is no cost of service basis for a stepped energy charge and the current rate design exacerbates an intra-class subsidy. Additionally, Montana-Dakota is the only regulated electric utility in Wyoming with an inverted block rate for residential service.

There is no cost based rational, nor an avoided cost, for additional overall usage in a monthly billing period that makes it more expensive for the utility to produce the next kilowatt-hour above 1,000 kWh.

Intra-class subsidies always exist when a portion of fixed costs are recovered through volumetric rates. Increasing the per kWh energy charge for usage above 1,000 kWh further increases the intra-class subsidy provided by higher use customer to smaller use customers.

Q. Please describe the Company's proposed rate design for each of the remaining rate schedules and how you propose collecting the allocated final increase from each of those rate schedules.

A. Residential Controlled Service Rate 11 is closed to new customers as the equipment that was used for load control is no longer functional as discussed in the Direct Testimony of Ms. Bosch. The proposed Basic Service Charge is proposed to increase from $0.167 to $0.194 per day, resulting in a monthly charge of $5.90 which is equal to the customer-related unit cost of service.

Small General Service Rate 20 is available to non-residential customers with demands less than 50 Kw per month[3]. The rate includes three service levels: Demand-Primary, Demand-Secondary and Non Demand. The Basic Service Charge is proposed to increase from $0.923 per day to $3.00 per day for primary demand, and from $0.923 per day to $1.38 per day for secondary demand and non-demand service levels. The Basic Service Charges were separated to better reflect the customer-related costs of the different services levels. The proposed demand charge increases from $5.15 per Kw to $8.76 per Kw for demands less than 10 Kw for primary service level customers and from $5.62 to $9.55 per Kw for secondary service level customers. The demand charge is increased from $9.83 per Kw to $14.75 per Kw for demands greater than 10 Kw for primary service level customers and from $10.30 to $15.45 per Kw for secondary service level customers. The remaining revenue required to collect the assigned revenue requirement, after increasing the Basic Service Charge rate and demand charges, is proposed to be collected through the flat energy charge for each level of service.

The Basic Service Charge for Irrigation Service Rate 25 is increased from $1.540 per day to $2.868 and increased for Irrigation Service Rate 26 from $1.540 per day to $2.750 per day. The proposed demand charge increases from $6.55 per Kw to $11.50 per Kw for all demand levels for Rate 25 customers. For Rate 26 Irrigation Service customers the proposed demand charge is increased from $7.77 to $13.50 per Kw for on-peak demands and increased from $2.81 per Kw to $5.00 per Kw for off-peak demand charge. The remaining revenue required

[3] Small General Controlled Service Rate 22 has been combined into Rate 20 in the Company's rate design proposal in this case as further discussed in the Direct Testimony of Stephanie Bosch.

to collect the assigned revenue requirement, after increasing the Basic Service Charge rate and demand charges, is proposed to be collected through the flat energy charge for each level of service.

Large General Electric Service 39 is applicable to demand metered services exceeding 50 Kw. An increase in the Basic Service Charge for primary service level customers is proposed resulting in a monthly charge of $300.00. The Basic Service Charge applicable to secondary service customers under Rate 39 is proposed to increase to $95.00 per month. For Rate 39 customers the Company proposes to increase the demand charge from $11.23 per Kw to $16.14 per Kw for primary service level customers and from $11.70 per Kw to $15.78 per Kw for secondary service level customers. The remaining revenue required to collect the assigned revenue requirement, after increasing the Basic Service Charge rate and demand charges, is proposed to be collected through the flat energy charge for each level of service.

Lighting services are currently provided under Outdoor Lighting Service Rate 24 and Public Lighting Service Rate 41. With regard to these schedules, the only change proposed is a change to the flat energy charge caused by the increase allocated to these rate classes.

Q. Please further discuss your proposal to increase the Basic Service Charge component of the previously identified rate schedules.

A. The Basic Service Charge component of each rate schedule has been set at or near the cost per customer component identified in the embedded class cost of service study with consideration of the impacts on other rate components of the schedules. As shown on Statement K, the customer component reflects those costs that vary by the number of customers served in each rate class. This

includes the investment in meters and services that directly serve each individual customer, and a portion of the investment in poles, overhead and underground conductors, and line transformers. Through the COSS, these facilities have been determined to be associated with the minimum investment necessary to provide service to a customer regardless of the energy or peak load requirements of that customer.

The Basic Service Charge can be characterized as a connection charge for access to service. It is imperative that appropriate fixed costs be collected through the Basic Service Charge in order to minimize intra-class subsidies and provide customers with the appropriate economic price signals. Increasing the Basic Service Charge to the amount identified as necessary to recover customer-related fixed costs does not provide a disincentive to using energy wisely. Customers' conservation efforts are rewarded through lower bills because of lower energy consumption. Other benefits of better aligning cost recovery with cost causation include:

- Mitigating the impact of significantly colder or warmer than normal weather on customers' bills;
- Residential customers' bills will be more stable as approximately 29 percent of the proposed class revenue will be fixed each month and not dependent on changes in weather; and
- Provides a better match of revenues to the investment made to serve each customer.

If fixed costs are not recovered from fixed charges, average or higher than average use customers subsidize low use customers, regardless of the reason a customer uses less energy than average.

VII. CUSTOMER BILL IMPACTS

Q. Has Montana-Dakota prepared a bill comparison for its Residential Service customers?

A. As seen in Exhibit No.___(RJA-3), Bill Comparison Annual Effects, the Basic Service Charge under Residential Rate 10 is proposed at $1.160 per day which reflects an average monthly charge of $35.28, an increase of approximately $11.89 per month from the currently effective charge. This proposed charge reflects the $31.27 customer component identified in the embedded class cost of service as shown on Statement K, Schedule K-1, page 1 plus some additional fixed demand-related costs. The Basic Service Charge is collected on a daily basis in order to avoid prorating the monthly charge when customers are in service for less than 30 days, on average, or when a billing period extends beyond a 30 day average. A typical residential customer using 9,700 kWh per year will see an increase in their electric service bill of $27.84 on an average monthly basis as shown on Exhibit No. ___ (RJA-3). Statement L presents the stratified bill comparisons over ranges of annual billed dollars on page 17, including the number of customers in each strata and the average monthly kWh usage.

Q. Does this conclude your direct testimony?

A. Yes.

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
45

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

FortisBC Energy, Inc. (2016 – 2018, 2021-2022)
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.

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 were 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).

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

Manitoba Hydro (2024-2025)

Retained by the client to provide a financial benchmarking framework that will ensure its financial health, its ability to achieve long-term financial targets, and will support organizational decision making. Reviewed regulatory jurisdictions in Canada and the U.S. with similarly situated provincially or publicly owned electric utilities to gain an understanding of how each regulatory jurisdiction uses financial metrics in rate setting, i.e., which metrics are relied upon and how do those metrics factor into the determination of authorized rates. Review included at least one Crown or municipal utility in each Canadian province, U.S. public power hydroelectric utilities, and opportunistically brought in relevant research from other sectors. Short-listed a group of

financial metrics used to assess financial health for modeling to test financial outcomes of metrics and targets for consideration by Executive Team (in progress).

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 into 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, 2021-2022)

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, 2024-2025)

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. Mr. Amen provided expert testimony in PGW's 2024 general rate proceeding supporting the continuation of the WNA, supplemented by the addition of a Revenue Normalization Adjustment ("RNA") mechanism. (Case pending)

Public Service Company of Colorado (Xcel) (2024)

Mr. Amen was engaged to provide expert testimony presenting and supporting the Company's proposed Revenue Stability Mechanism ("RSM"). The RSM is a total revenue decoupling mechanism intended to separate the Company's revenue from the volume of gas it sells to help support Colorado's state decarbonization goals. The Colorado Senate Bill 21-264 directed gas utilities to submit "Clean Heat Plans" to reduce carbon dioxide and methane emissions toward Clean Heat targets in specific years. Potential emissions reduction measures include energy efficiency, biomethane, hydrogen, recovered methane, beneficial electrification of customer end users, and leak detection, among others.

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, 2023-2024)

Mr. Amen provided allocated cost of service, class revenue apportionment, rate design for natural gas infrastructure mechanisms, and expert witness support for two of the utility's gas general rate case before the Arkansas Public Service Commission. The cases resulted in settlements before the Arkansas PSC.

Until Electric System, Northern Utilities, Fitchburg Gas & Electric (2021-2022, 2023-2024)

Mr. Amen provided allocated cost of service ("ACOSS"), 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.

For Until affiliate, Fitchburg Gas & Electric, Mr. Amen conducted an ACOSS to determine the embedded costs of serving the Company's gas distribution customers and support its rate design efforts in its base distribution rate proceeding before the Massachusetts Department of Public Utilities. Sponsored expert witness support for the ACOSS, class revenue apportionment, proposed rate design, and bill impacts. Also sponsored the weather normalization and annualization of its billing determinants and a Marginal Cost of Service Study.

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, 2024-2025)

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 MDU electric general rate case filings in Montana and North Dakota (2022), including a marginal cost study in Montana, and allocated cost studies, revenue apportionment and rate design in both jurisdictions.

Mr. Amen recently supported gas general rate case filings in MDU's Idaho affiliate, Intermountain Gas (2022-2023) and Washington affiliate, Cascade Natural Gas (2024). Testimony support included a class level, design day load studies across the two utilities' temperature zones, using a combination of AMI penetration and monthly billing data, class allocated cost of service study, class revenue apportionment, and rate design.

Mr. Amen supported gas and electric general rate case filings in MDU's South Dakota service territory (2023), including gas and electric allocated cost studies, revenue apportionment and rate design, and are currently supporting MDU gas cases in Montana and Wyoming (both filed August 2024).

Chesapeake Utilities Corporation (2020 – 2021, 2024-2025)

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.

Mr. Amen is currently providing testimony support for Chesapeake Utility's Delaware general rate case (filed August 2024), including a Lead Lag study supporting cash working capital, determination of normal weather, cost of service and rate design principles, allocated cost of service results, revenue apportionment, and a modified version of a prior weather normalization adjustment (WNA) rider.

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 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 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, 2024 - 2025)

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. Ongoing work involves innovative rate programs and demand forecasting.

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 related 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
- Idaho Public Utilities 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
- Wyoming Public Service 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
ELECTRIC UTILITY - WYOMING

	Total Montana	Rate 10 Residential	Rate 11 Controlled Residential	Rate 20 Sm General Primary	Rate 20 Sm General Secondary	Rate 22 Sm General Controlled	Rate 24 Outdoor Lighting	Rate 25 Irrigation	Rate 26 Irrigation	Rate 37 Lg General Secondary	Rate 39 Lg General Primary	Rate 39 Lg General Secondary	Rate 41 Public Lighing
Revenue to Cost Ratio Under Current Rates	0.71	0.72	0.49	0.33	0.66	0.46	1.05	0.30	0.25	5.09	0.79	0.83	1.10
Parity Ratio at Current Rates	1.00	1.01	0.69	0.46	0.93	0.65	1.48	0.42	0.35	7.17	1.11	1.17	1.55
Revenues at Equalized Rates of Return													
Revenue Increase	7,507,709	4,248,033	212,425	18,533	1,588,569	3,868	(469)	605,565	29,841	(2,002)	249,764	557,299	(3,717)
Total Revenue at Equalized Rates of Return	25,508,382	14,984,864	417,658	27,469	4,708,687	7,116	9,131	862,393	39,622	489	1,181,102	3,231,849	38,002
Parity Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Scenario A: Equal Percentage Increase (System Average)													
Revenue Increase	7,507,709	4,478,110	85,598	3,727	1,301,337	1,355	4,004	107,118	4,079	1,039	388,442	1,115,500	17,400
Total Revenue at System Average	25,508,382	15,214,941	290,831	12,663	4,421,455	4,603	13,604	363,946	13,860	3,530	1,319,780	3,790,050	59,119
Percent Increase	41.71%	41.71%	41.71%	41.71%	41.71%	41.72%	41.71%	41.71%	41.70%	41.71%	41.71%	41.71%	41.71%
Parity Ratio	1.00	1.02	0.70	0.46	0.94	0.65	1.49	0.42	0.35	7.22	1.12	1.17	1.56
Scenario B: No Class Increase Above Parity													
Revenue Increase	7,507,709	4,241,845	212,425	18,533	1,588,569	3,868	0	605,565	29,841	0	249,764	557,299	0
Total Revenue as Proposed	25,508,382	14,978,676	417,658	27,469	4,708,687	7,116	9,600	862,393	39,622	2,491	1,181,102	3,231,849	41,719
Percent Increase	41.71%	39.51%	103.50%	207.40%	50.91%	119.09%	0.00%	235.79%	305.09%	0.00%	26.82%	20.84%	0.00%
Parity Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.05	1.00	1.00	5.09	1.00	1.00	1.10
Scenario C: Maximum Increase of 1.5 times system; Minimum 0.75 times system; no Controlled Rate subsidy													
Parity, Min. 0.75 times, Max increase 1.5 times system average	7,284,205	4,248,033	128,398	5,591	1,588,569	2,032	3,003	160,676	6,119	779	291,331	836,624	13,050
Class eligible for allocation of balance		YES	NO	NO	YES	NO	NO	NO	NO	NO	NO	NO	NO
Allocation of Balance	223,504	170,065			53,439								
Revenue Increase	7,507,709	4,418,098	128,398	5,591	1,642,008	2,032	3,003	160,676	6,119	779	291,331	836,624	13,050
Elimination of Controlled Rate Subsidy	0	(84,027)	84,027		(1,836)	1,836							
Total Revenue Increase	7,507,709	4,334,071	212,425	5,591	1,640,172	3,868	3,003	160,676	6,119	779	291,331	836,624	13,050
Total Revenue	25,508,382	15,154,929	333,631	14,527	4,762,126	5,280	12,603	417,504	15,900	3,270	1,222,669	3,511,174	54,769
Percent Increase	41.71%	40.37%	103.50%	62.57%	52.57%	119.09%	31.28%	62.56%	62.56%	31.27%	31.28%	31.28%	31.28%
Percent Increase w/Fuel	24.36%	25.59%	38.70%	34.85%	30.71%	48.33%	11.39%	39.84%	48.14%	26.57%	15.27%	15.11%	17.35%
Parity Ratio	1.00	1.01	0.80	0.53	1.01	0.74	1.38	0.48	0.40	6.69	1.04	1.09	1.44

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - WYOMING
Summary of Rate Design Results

Rate Class	Revenue Before Increase					Proposed Total Revenues		
	Basic Service Charge	Energy	Demand	Fuel	Total	Total Revenue	Revenue Increase $	Revenue Increase %
Residential Service								
Rate 10	$4,140,665	$6,596,166		$6,202,982	$16,939,813	$21,273,709	$4,333,896	25.58%
Rate 11	42,851	162,382		343,730	548,963	761,414	212,451	38.70%
	4,183,516	6,758,548		6,546,712	17,488,776	22,035,123	4,546,347	26.00%
Small General Service								
Rate 20	981,800	1,082,861	1,067,640	2,233,256	5,365,557	7,015,086	1,649,529	30.74%
Rate 22								
	981,800	1,082,861	1,067,640	2,233,256	5,365,557	7,015,086	1,649,529	30.74%
Irrigation Service								
Rate 25	67,358	74,749	114,721	146,452	403,280	563,959	160,679	39.84%
Rate 26	4,360	2,552	2,869	2,931	12,712	18,831	6,119	48.14%
	71,718	77,301	117,590	149,383	415,992	582,790	166,798	40.10%
Large General Service								
Rate 37	792	48	1,651	441	2,932	3,696	764	26.06%
Rate 39	132,192	591,908	2,881,788	3,837,814	7,443,702	8,571,224	1,127,522	15.15%
	132,984	591,956	2,883,439	3,838,255	7,446,634	8,574,920	1,128,286	15.15%
Lighting								
Rate 24		9,600		16,773	26,373	29,377	3,004	11.39%
Rate 41		41,719		33,499	75,218	88,271	13,053	17.35%
		51,319		50,272	101,591	117,648	16,057	15.81%
Total Wyoming Electric	$5,370,018	$8,561,985	$4,068,669	$12,817,878	$30,818,550	$38,325,567	$7,507,017	24.36%

Docket No. 20004-___ER-25
Exhibit No.___(RJA-2)
Page 1 of 1

MONTANA-DAKOTA UTILITES CO.
ELECTRIC UTILITY - WYOMING
Bill Comparison Annual Effects
Residential Rate 10

Month	Energy Use	Current Bill	New Bill	$ Change	% Change
January	1,100	$121.64	$153.80	$32.16	26.44%
February	900	100.02	128.90	28.88	28.87%
March	800	93.61	121.66	28.05	29.96%
April	800	92.84	120.50	27.66	29.79%
May	700	84.89	110.95	26.06	30.70%
June	600	75.40	99.08	23.68	31.41%
July	800	93.61	121.66	28.05	29.96%
August	1,000	111.05	143.09	32.04	28.85%
September	800	92.84	120.50	27.66	29.79%
October	700	84.89	110.95	26.06	30.70%
November	600	75.40	99.08	23.68	31.41%
December	900	102.33	132.38	30.05	29.37%
12-Month Total	9,700	$1,128.52	$1,462.55	$334.03	29.60%
Average Bill		$94.04	$121.88	$27.84	

Current Rate 10 1/		
Basic Service Charge	$0.769	per day
Energy Charge - 1st 1,000 Kwh	$0.04299	per Kwh
Energy Charge - Over 1,000 Kwh	$0.06171	per Kwh
Fuel & Purchased Power 2/	$0.04422	per Kwh

Rate 10 Proposed		
Basic Service Charge	$1.160	per day
Energy Charge	$0.06291	per Kwh
Fuel & Purchased Power 2/	$0.04422	per Kwh

1/ Rates effective May 1, 2018 in Docket No. 20004-135-ER-18 and PSCA effective May 1, 2025 in Docket No. 20004-170-EM-25 excluding surcharge.
2/ Pro Forma Fuel & Purchased Power

MONTANA-DAKOTA UTILITIES CO.

Before the Wyoming Public Service Commission

Docket No. 20004-____-ER-25

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 rate 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 area 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 2015.

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

A. Yes. I have previously presented testimony before this Commission and the Public Service Commissions of Montana and North Dakota and the Public Utilities Commissions of Minnesota and South Dakota.

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

A. The purpose of my testimony is to present the pro forma revenues, as included in Statement F, Schedule F-1, present the proposed rate schedules provided in Appendix B to the Application, and other proposed changes proposed to the Company's electric tariff.

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

A. I am sponsoring Statement F, Schedule F-1 and the proposed rate schedules provided in Appendix B to the Application with the exception of the proposed changes to the Power Supply Cost Adjustment Rate 50 tariff which is sponsored by Ms. Tara Vesey. I am also sponsoring Exhibit No. __(SB-1) Interruptible Large Power Demand Response Rate 38 and Exhibit No. __(SB-2) which is the determination of the proposed Rate 38 bill credit, Exhibit No. __(SB-3) Reliability and Safety Infrastructure Rider Rate 55 and Exhibit No. __(SB-4) which reflects an illustrative example of the recovery of the RSIR costs by rate class and Exhibit No. __(SB-5) Summary Billing Plan Rate 123.

Pro Forma Revenue Analysis

Q. Please explain the calculation of revenues at current rates included in Statement F, Schedule F-1?

A. As shown in Statement F, Schedule F-1, the Company applied the Basic Service Charges, Energy Charges, and Demand Charges applicable under each rate schedule, as authorized in Docket No. 20004-135-ER-18, to the pro forma customers, energy use, and demand to derive the revenues shown on Statement F, Schedule F-1 pages 6 through 18. The fuel rates reflect the Power Supply Cost Adjustment rates developed by Ms. Tara Vesey.

Q. The Commission recently approved changes to Parallel Generation Rate 57 in Docket No. 20004-171-ET-25 where Montana-Dakota requested revisions to the tariff that affected Rate 57's (Rate 57) Basic Service Charge, amongst other changes. Are the changes authorized to the Basic Service Charges in that docket reflected in Statement F, Schedule F-1?

A. No, not at this time. In that docket, the Company noted three customers whose generating facilities exceeded the 25 Kw maximum provided for under the net metering statute and the Company's Net Metering Service Rate 58 (Rate 58) schedule. Upon approval of the Company's requested changes, customers with generating facilities greater than 25 Kw would see the netting of their service stopped as provided for under Rate 58 and moved to Rate 57 where the customers'

service would no longer be netted and an additional monthly Rate 57 Basic Service Charge would be applicable depending on the type and service level of the customer. It is anticipated the three customers' intent is to continue to offset their electric requirements and therefore be considered a Partial Requirements Customer under the now authorized[1] tariff changes. All three customers have single phase service.

As the three customers are currently under a Rate 58 agreement, new agreements under Rate 57 are necessary. At this time, the new agreements are outstanding and therefore not reflected in the case. Assuming the Company's assumption is correct regarding the customers' intent, the Company would receive an additional $3.30 per month per customer or a total annual increase in revenue of $118.80 under the new Rate 57 Basic Service Charges.

Proposed New Rate Schedules

Q. Please explain the first new rate schedule, Interruptible Large Power Demand Response Rate 38, attached as Exhibit No. ___(SB-1).

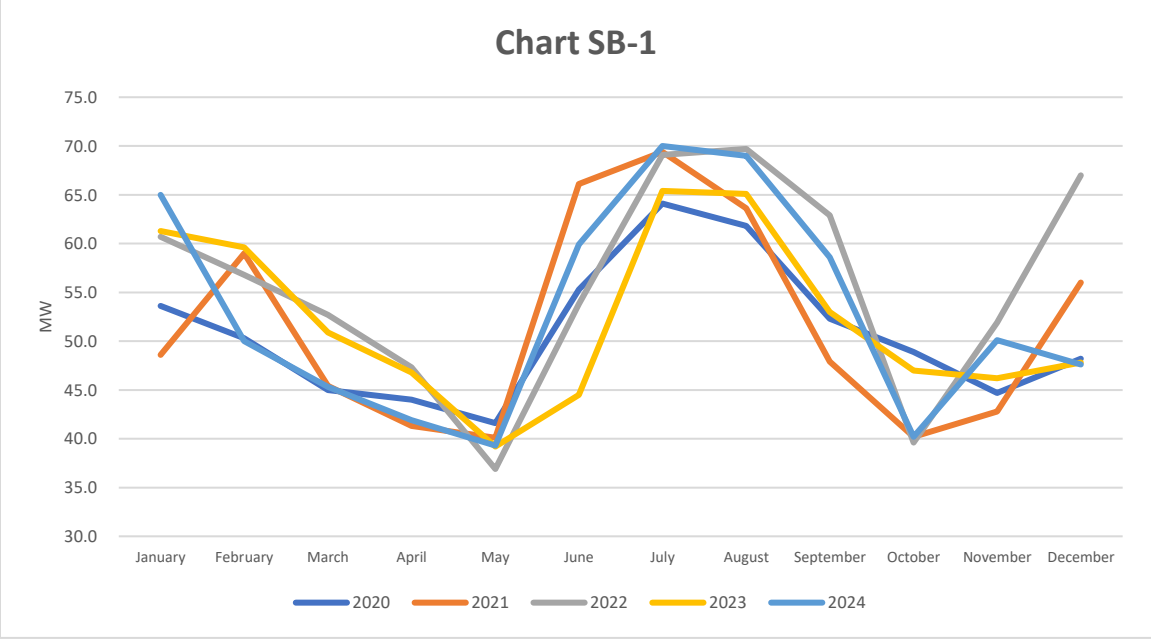
A. Montana-Dakota is proposing a new optional rate schedule to customers who have a demand of 500 Kw or more where at least 75 percent of the customer's load is available for interruption up to 100 hours annually. In exchange for the Company's ability to interrupt, participating customers would receive a bill credit each month applicable to their contracted interruptible Kw.

[1] Commission approved the Company's requested changes at the May 15, 2025 Agenda Meeting effective June 1, 2025.

Q. Why propose Rate 38?

A. Montana-Dakota's Wyoming electric customers are currently supplied power through a 25 MW ownership of the Wygen III generating station, a purchase agreement with the City of Sheridan from a small hydroelectric Federal Energy Regulatory Commission qualifying facility, and a wholesale power purchase agreement from Black Hills Power Inc. These arrangements provide over 74 MW of demand and energy resources.

The Company's Sheridan System's peak has ranged from 64.1 MW in 2020 to 70 MW in 2024 as shown in Chart SB-1. The Company's 2022 Electric Resource Plan, filed with the Commission on December 28, 2022 in Docket No. 20004-158-EA-22, indicates the peak is expected to grow at an average rate of 1.0 percent through 2031 equating to a summer peak of 72.8 MW in 2031.



As the Company is nearing the 74 MW provided for under committed resources and interest continues to be fielded regarding possibly locating a data center type facility in Montana-Dakota's Wyoming service territory, the Company considered how best to serve these larger loads yet have the capability to interrupt when reaching peak supply conditions.

Proposed Rate 38 provides the Company with such capability while also benefiting all customers. The new rate schedule provides Montana-Dakota with load serving flexibility when reaching peak supply conditions as the Company is able to interrupt customer load by calling an event. These larger customers who typically have higher load factors will benefit through the receipt of a monthly bill credit in exchange for such flexibility. This exchange further helps manage and/or delay having to build or contract for incremental generation resources needed during peak times. Finally, all customers will benefit from the introduction of a future large customer load coming online thus providing the opportunity to share in the recovery of the Company's costs.

Q. Please describe how Rate 38 will work.

A. Interested customers who have a demand of 500 Kw or more would enter into an electric service agreement with the Company where the customer would annually select their Baseline Non-Interruptible Kw which would not be subject to interruption. The remaining Interruptible Kw must equal 75 percent of the customer's expected load at a minimum.

Once in service, Montana-Dakota could call on the customer to interrupt their service when peak conditions are approaching. A participating customer would be required to reduce service to their respective Baseline Non-Interruptible Load within 30 minutes of the Company's notification to interrupt unless agreed otherwise by the parties to the agreement. In return for the Company's ability to interrupt a customer's service, participating customers would receive a bill credit of $2.75 per Interruptible Kw each month.

Montana-Dakota reserves the right to call up to 100 hours of interruption annually, excluding any hours interrupted for a summer or winter performance capability test. The penalty for failure to interrupt when called will be $12.00 per Kw applicable to the Interruptible Kw specified in the electric service agreement. Following two failures to interrupt within a twelve-month period, the customer may be moved to the otherwise applicable rate.

Q. How did Montana-Dakota determine the bill credit rate of $2.75 per Interruptible Kw?

A. The starting point for the proposed bill credit is the Company's Class Cost of Service Study (CCOS) as shown on Exhibit No.__(SB-2). The Total Cost of Service Study results were then further separated into Demand – Production, Demand – Transmission, and Demand – Distribution & Other. While the Company's CCOS doesn't readily provide this breakout, the separation was extrapolated based on the allocated

demand plant in service costs from the CCOS for the Company's rate classes.

The allocated production-related demand costs were then divided by the pro forma demand billing determinants for a total demand-production cost of $33.837 per Kw. To factor in the potential impact on this cost of a Rate 38 customer coming online, the Company added incremental load of 1 to 5 MW to the pro forma billing determinants. The results were then averaged to derive the $2.75 per Kw bill credit.

Q. How would the bill credits be accounted for and where would those costs be recovered?

A. The dollars credited to participating Rate 38 customers would be considered a capacity-related cost and recovered through the Company's Power Supply Cost Adjustment.

Q. How did the Company determine the other charges proposed under Rate 38?

A. As the service provided under Rate 38 is the same level of service provided under Rate 39 absent the ability to interrupt, Montana-Dakota is proposing the remaining charges be the same as those proposed under Rate 39.

Q. Please provide an illustrative example of a Rate 38 customer's bill.

A. Assuming a new customer load of 2 MW where the customer has elected 75 percent of their load be subject to interruption, which is the minimum provided for under the new rate schedule, a Rate 38's customer

bill will look very similar to a Rate 39's customer bill as shown in the example below for secondary service. The only difference is the addition of the Interruptible Bill Credit line which amounts to about a 4.0 percent reduction in a customer's bill, at the proposed rates, under the 2 MW scenario.

Interruptible Large Power Demand Response Rate 38 - Secondary			Monthly Billing Determinants	Monthly Bill
Basic Service Charge	$95.00	per month		$95.00
Demand Charge	$15.78	per Kw of Billing Demand	2,000	$31,560.00
Interruptible Bill Credit	($2.75)	per Kw of Interruptible Demand	1,500	(4,125.00)
Energy Charge	$0.00479	per Kwh	1,440,000	$6,897.60
PSCA (Pro Forma)	$0.04422	per Kwh	1,440,000	$63,676.80
				$98,104.40

Q. Does the Company offer customers an interruptible, demand response rate schedule in Montana-Dakota's other jurisdictions?

A. Yes, a similar rate schedule is offered to customers having a demand of 500 Kw or more in Montana and North Dakota. Under the rate, customers pay a reduced demand charge of $3.50 per Kw compared to the demand charges paid under the otherwise applicable large general service rate schedule in exchange for the Company's ability to interrupt when called upon.

Q. The second new rate schedule being proposed is Reliability and Safety Infrastructure Rider Rate 55, provided as Exhibit No. __(SB-3). Explain Rate 55.

A. As explained by other Company witnesses, Montana-Dakota is proposing a new rate mechanism designed to recover costs specific to projects encompassing reliability and safety improvements to the

Company's electric infrastructure in Wyoming. Rate 55 details the applicability, mechanics, time and manner of filing as well as how the rate will be applied to customers' bills if approved by the Commission.

Q. Other Company witnesses have discussed the reason for the proposed rider, the types of projects that will be included in the rider and the mechanics of the rider. Please expand on how the Reliability and Safety Infrastructure Rider (RSIR) rate will be calculated.

A. Upon determination of the revenue requirement to be recovered under Rate 55, Montana-Dakota will calculate the percentage increase from the Total Revenue, excluding the Power Supply Cost Adjustment revenue, as authorized in this electric rate case and discussed by Mr. Bradley Davison. This percentage increase will be the RSIR rate and will be applicable to all of the Company's rate schedules.

The RSIR rate will then be applied to the dollars billed under the Basic Service Charge, Energy Charge, and Demand Charge of each rate schedule and shown as a separate line item on each customer's bill. The following is an example of a Rate 10 customer's bill, excluding taxes, under the proposed rates and the illustrative RSIR rate of 2.63 percent.

Basic Energy Charge	30 Days x	$1.160	$34.80
Energy Charge	800 Kwh x	$0.06291	$50.33
Power Supply Cost Adj	800 Kwh x	$0.04422	$35.38
RSIR	$85.13	2.63%	$2.24
Total excluding taxes			$122.75

Q. The RSIR rate is being proposed as a percentage adder rate which differs from the traditional per unit rate. Why propose a percentage adder rate for the RSIR?

A. The Company opted to propose a percentage adder for the application of the RSIR as it will maintain the allocation of authorized revenue, excluding fuel, within the RSIR going forward. This maintenance is an important consideration as project costs will be recovered in a manner consistent with the rates the Commission authorizes in this case and that will remain in effect until such time as the Company files its next general rate case. At that time, any RSIR projects being recovered through the rider will be moved into base rates and new rates established. As shown in Exhibit No. __(SB-4), Rate 10 customers account for 59.083 percent of all revenues under the Company's proposed rates. Under the illustrative RSIR, Rate 10 customers will also account for 59.083 percent of Rate 55's revenues.

Additionally, the percentage adder application, to some degree, helps limit possible swings in cost recovery that can occur under a strictly volumetric application as the percentage adder is also applied to a customer's Basic Service Charge and Demand Charge (if applicable) offering a degree of cost recovery stability.

Q. The third new rate schedule proposed is Summary Billing Plan Rate 123 provided herein as Exhibit No. ___(SB-5). What is Summary Billing and why is Rate 123 being proposed?

A. Summary Billing Plan Rate 123 is an optional billing arrangement where qualifying customers with multiple premises 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 their multiple monthly Montana-Dakota bills into one account which in turn equates to one monthly bill with 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.

Proposed Changes to Controlled Electric Rates 11 and 22

Q. Before explaining the proposed changes to Special Residential Controlled Electric Service Rate 11 (Rate 11) and Special General Controlled Electric Service Rate 22 (Rate 22), please provide a brief background of these two rates.

A. Under Rates 11 and 22 today, electric service is provided to residential and general service customers who operate Company approved space and/or water heating equipment that historically provided Montana-Dakota the ability to remotely control or interrupt such electric

service during peak times. All other electric service at the premise is provided for under a separate meter and priced at the Company's otherwise applicable rate schedules.

The two rates were first instituted over thirty years ago when Montana-Dakota invested in a load management system for the Company's Sheridan, Wyoming service area in an effort to minimize the demand amounts billed under the power supply contract effective at that time. In exchange for the Company's ability to interrupt a customer's electric space and/or water heating service during peak heating times, customers taking service under Rates 11 and 22 would pay a reduced rate for their energy consumption. In 1997, the ratchet demand provision, under a new power supply contract, was eliminated and the need for controlling the peak was reduced. Following the new contract, Rates 11 and 22 were closed to new customers; however, the Company continued to operate the load management system in recognition of customer investments made in equipment for service under these controlled service rates.

In 2007, upgrades were made to the load management system. Following the upgrade, and in the Company's 2008 electric rate case, the two controlled rates were again opened to allow new customers to take their space and/or water heating service under the rates.

In 2022, Montana-Dakota requested Commission approval to close Rates 11 and 22 to new customers as the load management system was

again in need of an upgrade in order to continue operating the aging system. In spite of the Company's best efforts, Montana-Dakota continued to encounter issues with the load management system, hampering the ability to communicate with customers' equipment and therefore interrupt their space and/or water heating equipment. Any additional changes to the system or rates, beyond the requested closure of rates, was anticipated to be incorporated into the Company's next electric rate case.

The Commission approved Montana-Dakota's request to close Rates 11 and 22 to new customers in Docket No. 20004-157-ET-22. At that time, Montana-Dakota had 704 residential customers taking service under Rate 11 and 16 general service customers taking service under Rate 22. Today, there are 703 Rate 11 customers and 14 Rate 22 customers.

Q. What changes are now being proposed to Rates 11 and 22 as the rates have been closed to new customers since 2022?

Starting with Rate 22, Montana-Dakota is proposing to eliminate the general service controlled space heating rate schedule altogether as only 14 customers remain on the rate today and the bill impact is estimated to be minimal under today's rates. Under the Company's proposed plan, customers would see their Rate 22 service moved under the customers' otherwise applicable rate on their account and billed as one service until

such time as the customer undertakes electrical work at their premise and the two separate services can be re-wired into one service.

With 703 Rate 11 customers and an estimated bill impact of almost twenty percent to combine bill a customer's Rate 11 service with their Rate 10 service at current rates, Montana-Dakota is opting not to eliminate the residential controlled rate as it is doing with Rate 22. A number of alternatives were considered regarding the rate design of Rate 11 to help lessen the rate differential between Rates 10 and 11 in this case and set the stage to eliminate Rate 11 in a future rate case.

With the proposed elimination of the Rate 10 blocked energy charges, the Company opted to continue with the current structure to Rate 11 and allocate a greater increase to the rate. Today, Rate 11's Energy Charge is approximately 49 percent of Rate 10's first block and 34 percent of Rate 10's second block. Under the proposed rates, Rate 11's energy charge accounts for approximately 75 percent of Rate 10's proposed energy charge, a significant increase in aligning the energy charges and setting the stage to eliminate the rate in the Company's next rate case. The average customer taking service under Rates 10 and 11 will see an approximate total increase in their two services of 35 percent under the proposed rates.

Other Proposed Tariff Changes

Q. A number of changes are being proposed to Municipal Lighting Service Rate 41. Could you briefly outline the changes being proposed?

A. First, the Company is proposing to expand the availability of the rate schedule to include the lighting of all public streets, alleys, and other roads and right of ways, and to no longer limit the availability solely to those lighting facilities owned by a municipality. This expansion of availability necessitates a change to the title of the rate schedule to Public Lighting Service Rate 41.

Montana-Dakota is also proposing to now include the monthly Facilities Charges applicable to lighting facilities owned, installed, and maintained by the Company on the rate schedule. While these "rental type" charges are not new to the Company or the customer being billed the charges today, the Company has not previously included these charges on the Rate 41 schedule. The 2019 street lighting project afforded the Company the opportunity to standardize the lighting facilities the Company will now install and/or maintain for the customer and the associated monthly rate applicable for such facilities. The inclusion of the Facilities Charges on the rate schedule offers both the Company and customers a reference point as to the type of facilities and "rental charge" associated with such facilities. These charges are not applicable to lighting facilities owned by the customer and/or municipality.

And lastly, the Company is proposing to clarify the determination of the monthly energy usage when the lighting service is un-metered. Consistent with all other customers, un-metered Rate 41 customers are billed monthly; however, the determination of that monthly energy usage is computed using a daily consumption level times the number of days in a customer's billing period.

Q. Is the Company proposing any changes to the Company's Extension Policy Rate 104?

A. Yes. The Company is proposing to update the cost to revenue ratio identified in Rate 104 to reflect the costs and projected return included in this rate case. The cost to revenue ratio is used to determine if cost participation is warranted for an extension to proceed. Currently if the estimated project construction cost is greater than 2.684 times the estimated annual revenue, the extension will be made only with a contribution. Reflecting today's costs and projected return, Montana-Dakota is proposing a cost to revenue ratio of 3.781 to 1.

The other change the Company is proposing to Rate 104 is to exclude the power supply costs from the revenue used to determine cost participation. As the Company's power supply costs are pass-through costs, the use of margin to determine cost participation is a better representation of the dollars available to recover the project's investment.

Q. Would you briefly describe any additional changes the Company is proposing to the Company's electric tariff?

A. The Company is proposing the following changes to its electric tariff as clearly identified in the legislative copy of the tariff provided in Appendix B of the Application:

- The Company is proposing an entirely new volume of its electric rate book, designated herein as W.P.S.C Tariff No. 2, to supersede the current Tariff No. 1, in order to reflect the removal of “A Division of MDU Resources Group, Inc.” in the tariff header of all rate schedules.
- The rates described by Mr. Ron Amen have been incorporated into the proposed rate schedules.
- Replace the Power Supply Cost Adjustment section included under each rate schedule’s Rate provision with an Adjustment Clause provision that lists the adjustment clauses applicable to that rate schedule. Included under the Adjustment Clause provision will be Power Supply Cost Adjustment Rate 50 and proposed Rate 55.
- Propose a new non-metered service provision applicable under Small General Electric Service Rate 20 whereby the installation of a meter on a customer’s service may not be warranted. In the absence of a meter, customers would be billed a predetermined energy use each month based on the operating characteristics of the equipment being served, such as Wi-Fi equipment.
- Propose changes to Outdoor Lighting Service Rate 24 to reflect current practices.

- Introduce new or update existing provisions within the Company's General Provisions Rate 100 that:
  - Introduce a monthly Manual Meter Reading Charge assessed customers who request to have their electric meter read manually each month in lieu of the Company installing an AMR-equipped meter to obtain meter reads. (Rate 100, Section V.9 General Terms and Conditions/Manual Meter Reading Charge.)
  - Advise customers that over time rates will apply if the customer's call is received after 12:00 p.m. local time for service work to be performed after hours on that same workday. To avoid over time rates, a customer may schedule the service work for a future workday. (Rate 100, Section V.11 General Terms and Conditions/Utility Customer Services.)
  - Update select provisions of Rate 100 to align the Company's tariff with rule changes authorized in Docket No. 9000-137-XO-18.
  - Update the following charges included in Section VI. Miscellaneous Charge of Rate 100:
    - Increase the Returned Check Charge to $30.00 for consistency with the Returned Check Charge applicable under the Company's gas tariff.
    - Increase the Reconnect Charge for disconnection of service due to nonpayment or other causes to $35.00 to

reflect updated labor and equipment rates. The minimum charge of $140.00 was approved as part of the Company's tariff in Docket No. 20004-165-ET-24 and reflects the Company's current minimum charge.

- Increase the Reconnect Charge for the reconnection of service to seasonal or temporary customers to $35.00 for non-demand metered customers and $70.00 for demand metered customers to reflect updated labor and equipment rates. The minimum charge of $140.00 was approved as part of the Company's tariff in Docket No. 20004-165-ET-24 and reflects the Company's current minimum charge.
- Increase the minimum charge to $40.00 for a special test of a meter at customer's request to reflect updated labor costs.

- Add clarifying language select sub-sections of Section 600 – Metering under Electric Service Rules and Regulations Rate 110 regarding the installation of customer equipment ahead of the Company's meter.

- 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. Does this conclude your testimony?

A. Yes.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 43

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

AVAILABILITY:

In all communities served for power to customers having a demand of 500 Kw or more where at least 75 percent is available for interruption up to 100 hours annually. Electric energy for the interruptible load shall be supplied through a common customer meter used to serve the customer's total electrical load.

RATE:

Primary Service:

Basic Service Charge:	$300.00 per month
Demand Charge:	$16.14 per Kw of Billing Demand
Demand Response Credit:	$2.75 per Interruptible Kw of Interruptible Load
Energy Charge:	1.131¢ per Kwh

Secondary Service:

Basic Service Charge:	$95.00 per month
Demand Charge:	$15.78 per Kw of Billing Demand
Demand Response Credit:	$2.75 per Interruptible Kw of Interruptible Load
Energy Charge:	0.479¢ per Kwh

Adjustment Clauses: Service under this rate schedule is subject to the following adjustments as provided for in the referenced rates and any amendments or alterations thereto. See Rate Summary Sheet or referenced sheet number following rate schedule for current rate.

- Power Supply Cost Adjustment Rate 50 (Sheet No. 58)
- Reliability and Safety Infrastructure Rider Rate 55 (Sheet No. 60)

MINIMUM BILL:

Basic Service Charge plus the Demand Charge (500 Kw minimum).

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 43.1

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

PAYMENT:

Bills 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 or any amendments or alterations thereto.

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 500 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to Conditions of Service Rate 100, Section 700.

DETERMINATION OF INTERRUPTIBLE KW:

Interruptible Kw shall be the Billing Demand less the Baseline Non-Interruptible Load.

BASELINE NON-INTERRUPTIBLE LOAD:

Annually, customers must select a Baseline Non-Interruptible Load in Kw which shall not be subject to interruption. Customers must select a Baseline Non-Interruptible Load that results in at least 75% expected load being interrupted.

POWER FACTOR CLAUSE:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 95% lagging and 95% leading. If the customer operates outside this range, the maximum 15-minute integrated reactive demand of the customer for the month in reactive kilovolt amperes (Kvar) in excess of 33% of the maximum 15-minute integrated kilowatt demand for the same month will be billed at $2.50 per Kvar of such excess reactive demand.

GENERAL TERMS AND CONDITIONS:

1. The customer shall execute an electric service agreement with the Company which shall include a minimum term of service, the Baseline Non-Interruptible Load, and any additional customer costs incurred by Company for facilities, such as substations, electric lines, meters, switching devices, and circuit breakers that are necessary to provide service under this rate schedule.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 43.2

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

a. Electric service agreements shall also include contact information, method(s) of communication to initiate demand response event(s), and test procedures for calculating Baseline, Non-Interruptible Load.

2. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required electric service agreement. Enhancements and/or modifications to equipment may be required to ensure equipment functionality and/or communication with the Company's fixed network facilities. Such enhancements and/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.

3. Customer will be required to interrupt service within 30 minutes of the Company's notification to interrupt service unless agreed otherwise by the parties.

4. The penalty for non-performance by customer in response to a Company request to interrupt will be $12.00 per Kw applicable to the Interruptible Kw specified in the electric service agreement with the Company. After a second failure to perform within a 12-month period, the customer may be moved to the otherwise applicable rate at the Company's discretion.

5. The Company may request a summer and winter performance test each year, lasting up to one hour in length, to test the customer's interruption capability and Baseline Non-Interruptible Load. Scheduled performance tests shall not count against the 100 hour limit

6. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

7. The foregoing schedule is subject to Rates 100-125 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.
Electric Utility - Wyoming
Determination of Rate 38 Bill Credit - Proposed
Docket No. 20004-____-ET-25

Total Cost of Service Required from Rates 1/	Total Wyoming	1 MW	2 MW	3 MW	4 MW	5 MW
Demand	$23,868,091					
Energy	7,212,597					
Customer	7,245,571					
	38,326,259					
Allocated Demand by Function 2/						
Demand - Production	$13,604,811					
Demand - Transmission	1,193,405					
Demand - Distribution & Other	9,069,875					
	23,868,091					
Pro Forma Billing Determinants						
Billed Kw 1/	402,070.0	402,070.0	402,070.0	402,070.0	402,070.0	402,070.0
Rate 38 Estimated Load		12,000.0	24,000.0	36,000.0	48,000.0	60,000.0
Total	402,070.0	414,070.0	426,070.0	438,070.0	450,070.0	462,070.0
$/Kw - Production	$33.837	$33.837	$33.837	$33.837	$33.837	$33.837
$/Kw - Production (including Rate 38)		$32.856	$31.931	$31.056	$30.228	$29.443
Reduction due to Rate 38		$0.981	$1.906	$2.781	$3.609	$4.394
					Average Reduction per Kw (1 MW to 5 MW)	$2.734

1/ Class Cost of Service Study Cost by Component Statement K, Schedule K-1.
2/ Class Cost of Service Study Embedded CCOS-Details Statement K, Schedule K-1:

Total Wyoming Electric	Demand Plant in Service	% of Total
Production	$67,700,191	57%
Transmission	5,790,771	5%
Distribution & Other	45,444,417	38%
	118,935,379	100%

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 60

RELIABILITY AND SAFETY INFRASTRUCTURE RIDER
Rate 55

APPLICABILITY:

This rate schedule provides a Reliability and Safety Infrastructure Rider (RSIR) recovery mechanism and specifies the procedure utilized to recover the revenue requirement associated with projects designed to improve the reliability and safety of the Company's electric infrastructure in Wyoming. RSIR costs recovered under the rider have been approved by the Commission and may include, but are not limited to, new or modified transmission-level projects specific to the improvement of power delivery and reliability to customers, replacement of pre-1985 underground distribution cables, and upgrades necessary for wildfire mitigation. Costs included in the rider are not reflected in the rates established in the most recent general rate case.

RELIABILITY AND SAFETY INFRASTRUCTURE RIDER:

1. The RSIR shall be calculated annually reflecting forecasted costs through year end of the filing year and through November of the following year.

2. The rider shall include a return requirement on the capital investment based on the rate of return authorized in the Company's most recent general electric rate case, in addition to operation and maintenance expenses, depreciation expense, and ad valorem tax expense associated with the eligible projects and a true-up of the previous year's rate.

3. A true-up will reflect any over- or under collection of revenue under the RSIR based on actual expenditures from the preceding twelve month recovery period. Interest shall be applied to the net over or under collection at one-twelfth of the Commission's authorized interest rate specified in accordance with Chapter 1, Section 3(a)(xvii) of the Commission's Rules.

4. The resulting revenue requirement shall be divided by the Total Revenue excluding the Power Supply Cost Adjustment revenue from Montana-Dakota's most recent general electric rate case to determine a percentage adder rate applicable to all rate schedules.

5. The percentage adder shall be applied to the dollars billed under the Basic Service Charges, Energy Charges, and Demand Charges of each rate schedule and identified as its own line on customers' bills.

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 60.1

RELIABILITY AND SAFETY INFRASTRUCTURE RIDER
Rate 55

6. When Montana-Dakota files its next general rate case, all project costs shall be removed from the RSIR and included in base rates. Only the true-up component (remaining rider balance) shall remain for recovery through the RSIR to be either collected or returned to customers over a subsequent period.

TIME AND MANNER OF FILING:

1. Each application by Montana-Dakota shall be made by means of a revised RSIR rate and tariff sheet reflecting updated project costs and true-up and the resulting rates.

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

3. The application shall be made 60 days prior to the implementation date of December 1 each year.

RSIR RATE: 0.00%

Montana-Dakota Utilities Co.
Electric Utility - Wyoming
Reliability & Safety Infrastructure Rider Rate 55
Cost Recovery by Rate Class
Illustrative Example

Statement L, Page 2

Rate Class	Revenue Before Increase (excl PSCA) - Pro Forma: Basic Service Charge	Energy Charge	Demand Charge	Total	Proposed Increase	Total Proposed Revenue	% of Total Revenue Excl Fuel	RSIR Rate	RSIR Allocated Costs to be Recovered	% of Total RSIR Allocated Costs
Residential										
Rate 10	$4,140,665	$6,596,166		$10,736,831	$4,333,896	$15,070,727	59.083%	2.63%	$396,360	59.083%
Rate 11	42,851	162,382		205,233	212,451	417,684	1.638%	2.63%	10,985	1.638%
Total Residential	4,183,516	6,758,548		10,942,064	4,546,347	15,488,411			407,345	
Small General										
Rate 20 Primary	1,011	4,044	3,881	8,936	5,592	14,528	0.057%	2.63%	382	0.057%
Rate 20 Sec - Demand	225,281	678,738	1,063,759	1,967,778	1,073,368	3,041,146	11.922%	2.63%	79,982	11.922%
Rate 20 Sec - Non Dem.	755,508	400,079		1,155,587	570,569	1,726,156	6.767%	2.63%	45,398	6.767%
Total Small General	981,800	1,082,861	1,067,640	3,132,301	1,649,529	4,781,830			125,762	
Irrigation										
Rate 25	67,358	74,749	114,721	256,828	160,679	417,507	1.637%	2.63%	10,980	1.637%
Rate 26	4,360	2,552	2,869	9,781	6,119	15,900	0.062%	2.63%	418	0.062%
Total Irrigation	71,718	77,301	117,590	266,609	166,798	433,407			11,398	
Large General										
Rate 37	792	48	1,651	2,491	764	3,255	0.013%	2.63%	86	0.013%
Rate 39 Primary	12,600	282,655	636,083	931,338	291,209	1,222,547	4.793%	2.63%	32,153	4.793%
Rate 39 Secondary	119,592	309,253	2,245,705	2,674,550	836,313	3,510,863	13.764%	2.63%	92,336	13.764%
Total Large General	132,984	591,956	2,883,439	3,608,379	1,128,286	4,736,665			124,575	
Lighting										
Rate 24 Outdoor		9,600		9,600	3,004	12,604	0.049%	2.63%	331	0.049%
Rate 41 Public		41,719		41,719	13,053	54,772	0.215%	2.63%	1,441	0.215%
Total Lighting		51,319		51,319	16,057	67,376			1,772	
Total Wyoming Electric	$5,370,018	$8,561,985	$4,068,669	$18,000,672	$7,507,017	$25,507,689	100.000%		$670,852	100.000%

Exhibit No. __(SB-4)
Page 1 of 1

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 191

SUMMARY BILLING PLAN
Rate 123

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

State of Wyoming
Electric Rate Schedule

W.P.S.C. Tariff No. 2
Original Sheet No. 191.1

SUMMARY BILLING PLAN
Rate 123

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.